JUL - 9 2015
OFFICE OF THE CLERK

Nos. 14-840 and 14-841

In the Supreme Court of the United States

FEDERAL ENERGY REGULATORY COMMISSION,
PETITIONER

v.

ELECTRIC POWER SUPPLY ASSOCIATION, ET AL.

ENERNOC, INC., ET AL., PETITIONERS

v.

ELECTRIC POWER SUPPLY ASSOCIATION, ET AL.

ON WRITS OF CERTIORARI
TO THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

JOINT APPENDIX
(VOLUME 1)

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PETITIONS FOR WRITS OF CERTIORARI FILED: JAN. 15, 2015
CERTIORARI GRANTED: MAY 4, 2015

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TABLE OF CONTENTS

Page

VOLUME 1

Court of appeals docket entries 1
R.2, Notice of Proposed Rulemaking (Mar. 18, 2010) 19
R.10, Comments of the Illinois Commerce Commission (May 6, 2010) 60
R.18, Comments of the Electric Power Supply Association (May 12, 2010) 80
Attachment 1, Implications for Consumers of the NOPR's Proposal to Pay the LMP for All Demand Response (May 12, 2010) 181
R.44, Notice of Intervention and Comments of the New York State Public Service Commission (May 13, 2010) 220
R.50, Comments of the Public Utilities Commission of Ohio (May 13, 2010) 236
R.55, Comments of Verso Paper Corp. in Support of the Notice of Proposed Rulemaking (May 13, 2010) 244
R.58, Comment of the Federal Trade Commission (May 13, 2010) 281
R.74, Comments of the Organization of MISO States (May 13, 2010) 302
R.76, Comments on Notice of Proposed Rulemaking of PJM Interconnection, L.L.C. (May 13, 2010) 314
R.79, Comments of the Delaware Public Service Commission (May 13, 2010) 348
R.82, Comments of Viridity Energy, Inc. 350
R.83, Comments of American Public Power Association and the National Rural Electric Cooperative Association (May 13, 2010) 382

Table of Contents—Continued: Page

R.86, Comments of the New York Independent System Operator, Inc. (May 13, 2010) 404
R.91, Notice of Intervention, Comments, and Request for Clarification of the Public Utilities Commission of the State of California (May 13, 2010) 425
R.93, Comments of Steel Producers (May 13, 2010) 439
R.94, Comments of EnerNOC in Response to Notice of Proposed Rulemaking (May 13, 2010) 452
R.100, Comments of ISO New England Inc. (May 13, 2010) 467
R.105, Comments of the Midwest Independent Transmission System Operator, Inc. (May 13, 2010) 535
R.113, Comments of Wal-Mart Stores, Inc. to the Notice of Proposed Rulemaking on Demand Response Compensation in Organized Wholesale Energy Markets (May 13, 2010) 558
R.123, Comments of Potomac Economics, Ltd. (May 13, 2010) 575
R.124, Comments of the Independent Market Monitor for PJM (May 13, 2010) 587
R.128, Joint Comments of Public Interest Organizations on Notice of Proposed Rulemaking (May 14, 2010) 599
R.131, Comments of Old Dominion Electric Cooperative on Notice of Proposed Rulemaking (May 14, 2010) 616
R.137, Reply Comments of Viridity Energy, Inc. 658

VOLUME 2

R.142, Reply Comments of the Electric Power Supply Association (June 30, 2010) 704
R.149, Reply Comments of the Demand Response Supporters (Aug. 30, 2010) 791

Table of Contents—Continued: Page

Attachment A, Reply Affidavit of Dr. Alfred E. Kahn 829

R.153, Transcript of Demand Response Compensation in Organized Wholesale Energy Markets Technical Conference (Sept. 13, 2010) (excerpts) 852

R.160, Speaker Materials of Megan Wisersky, Electric Planning Manager, Madison Gas & Electric Co on Behalf of Midwest Transmission Distribution Utilities, Presented at the Technical Conference, Demand Response Compensation/Organized Wholesale Energy Markets (Sept. 13, 2010) 926

R.187, Post-Technical Conference Comments of the American Public Power Association (Oct. 13, 2010) 941

R.201, Post Conference Comments of the Electric Power Supply Association (Oct. 13, 2010) 958

R.209, Comments of the Midwest Independent Transmission System Operator, Inc. (Oct. 13, 2010) 978

R.232, Joint Request for Rehearing of the Electric Power Supply Association, et al. (Apr. 14, 2011) 998

R.233, Request for Rehearing of the Organization of MISO States (Apr. 14, 2011) 1024

R.235, Request for Rehearing and Clarification of Old Dominion Electric Cooperative, American Public Power Association and the National Rural Electric Cooperative Association (Apr. 14, 2011) 1036

R.239, Request for Rehearing of the Edison Electric Institute (Apr. 14, 2011) 1075

R.240, Request for Rehearing of the Competitive Power Supply Associations (Apr. 14, 2011) 1118

Table of Contents—Continued: Page

Documents filed in FERC Docket No. EL09-68-000:
Supplemental Report and Submittal of PJM Interconnection, L.L.C. in Support of Further Commission Action on Rehearing (Aug. 26, 2009) 1235
Comments and Protest of Demand Response Supporters (Sep. 16, 2009) 1278
Attachment A, Affidavit of Alfred E. Kahn 1336
Attachment D, Affidavit of Ron Belbot On Behalf of Demand Response Supporters 1348

UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

Docket No. 11-1486

ELECTRIC POWER SUPPLY ASSOCIATION, PETITIONER

v.

FEDERAL ENERGY REGULATORY COMMISSION, ET AL., RESPONDENT

DOCKET ENTRIES

DATE	PROCEEDINGS
12/23/11	PETITION FOR REVIEW CASE docketed. [11-1486]
12/23/11	PETITION FOR REVIEW filed [1349754] by Electric Power Supply Association of a decision by federal agency [Service Date: 12/23/2011] Disclosure Statement: Attached; Certificate of Parties: Not Applicable to this Filing [11-1486]
	* * * * *
1/20/12	MOTION filed [1353650] by American Forest & Paper Association for leave to intervene [Disclosure Listing: Attached] [Service Date: 01/20/2012] [11-1486] (Mermin, Jonathan)
1/23/12	MODIFIED PARTY FILER—MOTION filed [1354045] by PPL ELECTRIC

DATE	PROCEEDINGS
	UTILITIES CORPORATION; PPL ENERGYPLUS, LLC; PPL BRUNNER ISLAND, LLC; PPL HOLTWOOD, LLC; PPL MAINE, LLC; PPL MARTINS CREEK, LLC; PPL MONTOUR, LLC; PPL SUSQUEHANNA, LLC; LOWER MOUNT BETHEL ENERGY, LLC for leave to intervene [Disclosure Listing: Attached] [Service Date: 01/23/2012] [11-1486]—[Edited 01/23/2012 by LMC] (Rizzo, Sandra)
1/23/12	MODIFIED PARTY FILER—*JOINT* MOTION filed [1354101] by Public Service Electric and Gas Company PSEG Power LLC PSEG Energy Resources & Trade LLC for leave to intervene [Disclosure Listing: Attached] [Service Date: 01/23/2012] [11-1486]—[Edited 01/23/2012 by LMC] (Moskowitz, Jodi)
1/23/12	MOTION filed [1354172] by Wal-Mart Stores Inc. for leave to intervene [Disclosure Listing: Attached] [Service Date: 01/23/2012] [11-1486] (Shelby, Joseph)
1/23/12	MODIFIED PARTY FILER—MOTION filed [1354189] by PJM Industrial Customer Coalition for leave to intervene [Disclosure Listing: Attached] [Service Date: 01/23/2012] [11-1486]—[Edited 01/24/2012 by LMC] (Weishaar, Robert)
1/23/12	INCORRECT DOCKET ENTRY-DISREGARD-already filed in lead case-MOTION filed [1354190] by Wal-Mart

DATE	PROCEEDINGS
	Stores Inc. for leave to intervene [Disclosure Listing: Attached] [Service Date: 01/23/2011] [11-1486]—[Edited 01/24/2012 by LMC] (Shelby, Joseph)
1/23/12	MODIFIED PARTY FILER—MOTION filed [1354191] by Coalition of Midwest Transmission Customers for leave to intervene [Disclosure Listing: Attached] [Service Date: 01/23/2012] [11-1486]—[Edited 01/24/2012 by LMC] (Weishaar, Robert)
1/23/12	MODIFIED PARTY FILER—MOTION filed [1354192] by Viridity Energy, Inc. for leave to intervene [Disclosure Listing: Attached] [Service Date: 01/23/2012] [11-1486]—[Edited 01/24/2012 by LMC] (Weishaar, Robert)
1/23/12	MODIFIED PARTY FILER—MOTION filed [1354194] by EnerNOC, Inc. for leave to intervene [Disclosure Listing: Attached] [Service Date: 01/23/2012] [11-1486]—[Edited 01/24/2012 by LMC] (Weishaar, Robert)
1/23/12	MODIFIED PARTY FILER—MOTION filed [1354201] by American Municipal Power, Inc. for leave to intervene [Disclosure Listing: Attached] [Service Date: 01/23/2012] [11-1486]—[Edited 01/24/2012 by LMC] (Newell, Gary)
1/23/12	MODIFIED PARTY FILER—MOTION filed [1354215] by PJM Interconnection, L.L.C. for leave to intervene [Disclosure Listing: Attached] [Service Date:

DATE	PROCEEDINGS
	01/23/2012] [11-1486]—[Edited 01/24/2012 by LMC] (Flynn, Paul)
1/25/12	MOTION filed [1354578] by Steel Producers for leave to intervene [Disclosure Listing: Attached] [Service Date: 01/25/2012] [11-1489, 11-1486] (Kopon, Owen)
1/27/12	MODIFIED PARTY FILER—MOTION filed [1355140] by EnergyConnect, Inc. for leave to intervene [Disclosure Listing: Attached] [Service Date: 01/27/2012] [11-1486]—[Edited 01/27/2012 by LMC] (Griff, Marvin)
	* * * * *
1/30/12	MOTION filed [1355539] by PJM Power Providers Group for leave to intervene [Disclosure Listing: Attached] [Service Date: 01/30/2012] [11-1486, 11-1489] (Rizzo, Sandra)
	* * * * *
3/8/12	MODIFIED PARTY FILER—MOTION filed [1362676] by Maryland Public Service Commission for leave to intervene [Disclosure Listing: Not Applicable to this Party] [Service Date: 03/08/2012] [11-1486]—[Edited 03/08/2012 by KRM] (Mitchell, Miles)
	* * * * *

DATE	PROCEEDINGS
3/12/12	MODIFIED PARTY FILER—MOTION filed [1363125] by Madison Gas and Electric Company (MGE), Missouri Joint Municipal Electric Utility Commission (MJMEUC), Missouri River Energy Services (MRES), Southern Minnesota Municipal Power Agency (SMMPA), and WPPI Energy (WPPI) (collectively, Midwest TDUs) for leave to intervene [Disclosure Listing: Attached] [Service Date: 03/12/2012] [11-1486, 11-1489, 12-1088, 12-1091, 12-1093]—[Edited 03/12/2012 by LMC] (Huang, William)
	* * * * *
3/13/12	MOTION filed [1363554] by Pennsylvania Public Utility Commission for leave to intervene [Disclosure Listing: Not Applicable to this Party] [Service Date: 03/13/2012] [11-1486]
	* * * * *
3/29/12	CLERK'S ORDER filed [1366274] granting motions for leave to intervene. [1363554-2] [1363125-2] [1362676-2] [1355539-2] [1355140-2] [1354578-2] [1354215-2] [1354201-2] [1354194-2] [1354192-2] [1354191-2] [1354189-2] [1354101-2] [1354045-2] [1353650-2] in 11-1486 [11-1486, 11-1489, 12-1088, 12-1091, 12-1093]
	* * * * *

DATE	PROCEEDINGS
6/6/12	PETITIONER BRIEF [1377461] filed by Electric Power Supply Association in 11-1486, American Public Power Association, National Rural Electric Cooperative Association and Old Dominion Electric Cooperative in 12-1088, Edison Electric Institute in 12-1091 [Service Date: 06/06/2012] Length of Brief: 12,617 Words. [11-1486, 11-1489, 12-1088, 12-1091, 12-1093] (Parrish, Ashley)
6/6/12	PETITIONER BRIEF [1377474] filed by California Independent System Operator Corporation in 11-1489, Public Utilities Commission of the State of California in 12-1093 [Service Date: 06/06/2012] Length of Brief: 4769 words. [11-1486, 11-1489, 12-1088, 12-1091, 12-1093] (Shonkwiler, Daniel)
	* * * * *
6/20/12	*JOINT* INTERVENOR FOR PETITIONER BRIEF [1379847] filed by Lower Mount Bethel Energy, LLC, PJM Power Providers Group, PPL Brunner Island, LLC, PPL Electric Utilities Corporation, PPL EnergyPlus, LLC, PPL Holtwood, LLC, PPL Maine, LLC, PPL Martins Creek, LLC, PPL Montour, LLC and PPL Susquehanna, LLC [Service Date: 06/20/2012] Length of Brief: 7,886 words. [11-1486, 11-1489, 12-1088, 12-1091, 12-1093] (Rizzo, Sandra)
	* * * * *

DATE	PROCEEDINGS
8/28/12	RESPONDENT BRIEF [1391793] filed by FERC in 11-1486, 11-1489, 12-1088, 12-1091, 12-1093 [Service Date: 08/28/2012] Length of Brief: 17,882 words. [11-1486, 11-1489, 12-1088, 12-1091, 12-1093] (Cafer, Holly)
	* * * * *
9/17/12	CORRECTED INTERVENOR FOR RESPONDENT BRIEF [1394798] filed by American Forest & Paper Association, Inc., Coalition of Midwest Transmission Customers, EnerNOC, Inc., EnergyConnect, Inc., Maryland Public Service Commission, PJM Industrial Customer Coalition, PJM Interconnection, L.L.C., Pennsylvania Public Utility Commission, Steel Producers, Viridity Energy Inc. and Wal-Mart Stores, Inc. [Service Date: 09/17/2012] Length of Brief: 8,683 words. [11-1486, 11-1489, 12-1088, 12-1091, 12-1093] (Weishaar, Robert)
	* * * * *

DATE	PROCEEDINGS
10/11/12	PETITIONER REPLY BRIEF [1399196] filed by Electric Power Supply Association in 11-1486, American Public Power Association, National Rural Electric Cooperative Association and Old Dominion Electric Cooperative in 12-1088, Edison Electric Institute in 12-1091 [Service Date: 10/11/2012] Length of Brief: 6,201. [11-1486, 11-1489, 12-1088, 12-1091, 12-1093] (Parrish, Ashley)
	* * * * *
10/11/12	PETITIONER REPLY BRIEF [1399199] filed by California Independent System Operator Corporation in 11-1489, Public Utilities Commission of the State of California in 12-1093 [Service Date: 10/11/2012] Length of Brief: 2491. [11-1486, 11-1489, 12-1088, 12-1091, 12-1093] (Shonkwiler, Daniel)
10/18/12	*JOINT* APPENDIX [1400461] filed [Volumes: 2] [Service Date: 10/18/2012] [11-1486, 11-1489, 12-1088, 12-1091, 12-1093] (Parrish, Ashley)
	* * * * *

DATE	PROCEEDINGS
1/15/13	LETTER FILED [1415252] by Electric Power Supply Association in 11-1486, American Public Power Association, National Rural Electric Cooperative Association and Old Dominion Electric Cooperative in 12-1088, Edison Electric Institute in 12-1091 pursuant to FRAP 28j advising of additional authorities [Service Date: 01/15/2013] [11-1486, 11-1489, 12-1088, 12-1091, 12-1093] (Reiter, Harvey)
1/17/13	LETTER FILED [1415793] by FERC in 12-1093 pursuant to FRAP 28j advising of additional authorities [Service Date: 01/17/2013] [11-1486, 11-1489, 12-1088, 12-1091, 12-1093] (Cafer, Holly)
1/29/13	LETTER FILED [1417824] by Coalition of Midwest Transmission Customers, EnerNOC, Inc., EnergyConnect, Inc., PJM Industrial Customer Coalition, Viridity Energy Inc. and Wal-Mart Stores, Inc. in 11-1486 pursuant to FRAP 28j advising of additional authorities [Service Date: 01/29/2013] [11-1486, 11-1489, 12-1088, 12-1091, 12-1093] (Weishaar, Robert)
	* * * * *
8/27/13	LETTER FILED [1453815] by California Independent System Operator Corporation in 11-1489 pursuant to FRAP 28j advising of additional authorities [Service Date: 08/27/2013] [11-1489] (Shonkwiler, Daniel)

DATE	PROCEEDINGS
	* * * * *
9/23/13	ORAL ARGUMENT HELD before Judges Brown, Edwards and Silberman. [11-1486, 11-1489, 12-1088, 12-1091, 12-1093]
	* * * * *
3/7/14	*JOINT* LETTER FILED [1482952] by Coalition of Midwest Transmission Customers, EnerNOC, Inc., EnergyConnect, Inc., PJM Industrial Customer Coalition and Viridity Energy Inc. in 11-1486 pursuant to FRAP 28j advising of additional authorities [Service Date: 03/07/2014] [11-1486, 11-1489, 12-1088, 12-1091, 12-1093] (Weishaar, Robert)
3/12/14	LETTER FILED [1483518] by Electric Power Supply Association in 11-1486 pursuant to FRAP 28j advising of additional authorities [Service Date: 03/12/2014] [11-1486, 11-1489, 12-1088, 12-1091, 12-1093] (Parrish, Ashley)
5/23/14	PER CURIAM JUDGMENT filed [1494279] that the rulings under review are vacated and remanded for the reasons in the accompanying opinion. Before Judges: Brown, Edwards and Silberman. [11-1486, 11-1489, 12-1088, 12-1091, 12-1093]

DATE	PROCEEDINGS
5/23/14	OPINION filed [1494281] (Pages: 16) for the Court by Judge Brown, DISSENTING OPINION (Pages: 28) by Judge Edwards [11-1486, 11-1489, 12-1088, 12-1091, 12-1093]
5/23/14	CLERK'S ORDER filed [1494282] withholding issuance of the mandate. [11-1486, 11-1489, 12-1088, 12-1091, 12-1093]
	* * * * *
7/7/14	PETITION filed [1501024] by Respondent FERC in 11-1486, 11-1489, 12-1088, 12-1091, 12-1093 for rehearing en banc. [Service Date: 07/07/2014 by CM/ECF NDA, US Mail] Pages: 11-15. [11-1486, 11-1489, 12-1088, 12-1091, 12-1093] (Cafer, Holly)
	* * * * *
7/7/14	MODIFIED EVENT—PETITION filed [1501079] by Intervenors for Respondent American Forest & Paper Association, Coalition of Midwest Transmission Customers, EnerNOC, Inc., EnergyConnect, Inc., PJM Industrial Customer Coalition, Steel Producers, Viridity Energy Inc. and Wal-Mart Stores, Inc. in 11-1486 for rehearing en banc [Service Date: 07/07/2014 by CM/ECF NDA] Pages: 11-15. [11-1486, 11-1489, 12-1088, 12-1091, 12-1093]—[Edited 07/08/2014 by LMF] (Weishaar, Robert)

DATE	PROCEEDINGS
7/7/14	PETITION filed [1501084] by Intervenor for Respondent Pennsylvania Public Utility Commission for rehearing en banc. [Service Date: 07/07/2014 by CM/ECF NDA, US Mail] Pages: 11-15. [11-1486] (Brown, Kriss)
	* * * * *
7/7/14	MODIFIED EVENT—PETITION filed [1501170] by Intervenor for Respondent Maryland Public Service Commission in 11-1486 for rehearing en banc. [Service Date: 07/07/2014 by CM/ECF NDA] Pages: 11-15. [11-1486, 11-1489, 12-1088, 12-1091, 12-1093]—[Edited 07/08/2014 by LMF] (Mitchell, Miles)
7/7/14	PETITION filed [1501174] by Intervenor for Respondent PJM Interconnection, L.L.C. in 11-1486 for rehearing en banc. [Service Date: 07/07/2014 by Email, CM/ECF NDA, US Mail] Pages: 11-15. [11-1486, 11-1489, 12-1088, 12-1091, 12-1093] (Flynn, Paul)
7/7/14	MODIFIED EVENT—PETITION filed [1501183] by Petitioner California Independent System Operator Corporation in 11-1489 for rehearing en banc. [Service Date: 07/07/2014 by CM/ECF NDA] Pages: 11-15. [11-1486, 11-1489]—[Edited 07/08/2014 by LMF] (Ward, Michael)

DATE	PROCEEDINGS
	* * * * *
7/11/14	LETTER FILED [1502080] by FERC in 11-1486, 11-1489, 12-1088, 12-1091, 12-1093 [Service Date: 07/11/2014] [11-1486, 11-1489, 12-1088, 12-1091, 12-1093] (Solomon, Robert)
7/18/14	CLERK'S ORDER filed [1503495] Upon consideration of respondent Federal Energy Regulatory Commission's petition for rehearing en banc, it is ORDERED, on the court's own motion, that within 15 days of the date of this order, petitioners Electric Power Supply Association, American Public Power Association, National Rural Electric Cooperative Association, Old Dominion Electric Cooperative, and Edison Electric Institute file a joint response to respondent's petition for rehearing en banc, not to exceed 15 pages. Absent further order of the court, the court will not accept a reply to the response. [1501024-2] [11-1486, 11-1489, 12-1088, 12-1091, 12-1093]

DATE	PROCEEDINGS
8/4/14	RESPONSE FILED [1505897] by Electric Power Supply Association in 11-1486, American Public Power Association, National Rural Electric Cooperative Association and Old Dominion Electric Cooperative in 12-1088, Edison Electric Institute in 12-1091 to petition for rehearing en banc [1501024-2] [Service Date: 08/04/2014 by CM/ECF NDA] Pages: 11-15. [11-1486, 11-1489, 12-1088, 12-1091, 12-1093] (Parrish, Ashley)
8/11/14	LETTER FILED [1521539] by Louisiana Public Service Commission [Service Date: 08/06/2014] [11-1486, 11-1489, 12-1088, 12-1091, 12-1093]
9/17/14	PER CURIAM ORDER, En Banc, filed (w/ statement) [1512775] granting the motion for invitation to file brief of amicus curiae Environmental Defense Fund, et al. [1501436-2]; The Clerk is directed to file the lodged Amicus brief [1501437-2] Before Judges: Garland, Henderson, Rogers, Tatel, Brown, Griffith, Kavanaugh, Srinivasan, Millett, Pillard, Wilkins, Edwards and Silberman*. [11-1486, 11-1489, 12-1088, 12-1091, 12-1093] (Circuit Judges Henderson and Millett did not participate in this matter) (*Senior Circuit Judge Silberman would deny the motion for reasons in the attached statement)

DATE	PROCEEDINGS
9/17/14	PER CURIAM ORDER, En Banc, filed [1512777] denying respondent's petition for rehearing en banc [1501024-2] Before Judges: Garland, Henderson, Rogers, Tatel, Brown, Griffith, Kavanaugh, Srinivasan, Millett, Pillard and Wilkins. [11-1486, 11-1489, 12-1088, 12-1091, 12-1093] (Circuit Judges Henderson and Millett did not participate in this matter)
9/17/14	PER CURIAM ORDER, En Banc, filed [1512778] denying the petitions for hearing en banc [1501183-2] [1501170-2], [1501079-2] [1501174-2], [1501084-2]. Before Judges: Garland, Henderson, Rogers, Tatel, Brown, Griffith, Kavanaugh, Srinivasan, Millett, Pillard, Wilkins, Edwards and Silberman. [11-1486, 11-1489, 12-1088, 12-1091, 12-1093] (Circuit Judges Henderson and Millett did not participate in this matter)
	* * * * *
9/22/14	MOTION filed [1513464] by American Forest & Paper Association, Coalition of Midwest Transmission Customers, EnerNOC, Inc., EnergyConnect, Inc., PJM Industrial Customer Coalition, Steel Producers, Viridity Energy Inc. and Wal-Mart Stores, Inc. in 11-1486 to stay mandate (Response to Motion served by mail due on 10/06/2014) [Service Date: 09/22/2014 by CM/ECF NDA] Pages: 16-20. [11-1486, 11-1489, 12-1088, 12-1091, 12-1093] (Weishaar, Robert)

DATE	PROCEEDINGS
9/22/14	MOTION filed [1513513] by FERC in 11-1486, 11-1489, 12-1088, 12-1091, 12-1093 to stay mandate (Response to Motion served by mail due on 10/06/2014) [Service Date: 09/22/2014 by CM/ECF NDA] Pages: 11-15. [11-1486, 11-1489, 12-1088, 12-1091, 12-1093] (Solomon, Robert)
9/30/14	RESPONSE IN OPPOSITION FILED [1514765] by Electric Power Supply Association in 11-1486, American Public Power Association, National Rural Electric Cooperative Association and Old Dominion Electric Cooperative in 12-1088, Edison Electric Institute in 12-1091 to motion to stay mandate [1513513-2], motion to stay mandate [1513464-2] [Service Date: 09/30/2014 by CM/ECF NDA] Pages: 1-10. [11-1486, 11-1489, 12-1088, 12-1091, 12-1093] (Parrish, Ashley)

DATE	PROCEEDINGS
10/20/14	PER CURIAM ORDER filed [1518074] ORDERED that the intervenors' motion be denied. It is FURTHER ORDERED that FERC's motion to stay issuance of mandate be granted. The Clerk is directed to withhold the mandate through December 16, 2014. If, within the period of the stay, respondent notifies the Clerk in writing that a petition for writ of certiorari has been filed, the Clerk is directed to withhold issuance of the mandate pending the Supreme Court's final disposition [1513464-2]; [1513513-2] Before Judges: Brown, Edwards* and Silberman. [11-1486, 11-1489, 12-1088, 12-1091, 12-1093] *Senior Circuit Judge Edwards would grant intervenors' motion.
12/8/14	MOTION filed [1526083] by FERC in 11-1486, 11-1489, 12-1088, 12-1091, 12-1093 to stay mandate (Response to Motion served by mail due on 12/22/2014) [Service Date: 12/08/2014 by CM/ECF NDA] Pages: 1-10. [11-1486, 11-1489, 12-1088, 12-1091, 12-1093] (Solomon, Robert)

* * * * *

DATE	PROCEEDINGS
12/12/14	RESPONSE IN OPPOSITION FILED [1526945] by Electric Power Supply Association in 11-1486, American Public Power Association, National Rural Electric Cooperative Association and Old Dominion Electric Cooperative in 12-1088, Edison Electric Institute in 12-1091 to motion to stay mandate [1526083-2] [Service Date: 12/12/2014 by CM/ECF NDA] Pages: 1-10. [11-1486, 11-1489, 12-1088, 12-1091, 12-1093] (Parrish, Ashley)
12/15/14	PER CURIAM ORDER filed [1527366] Upon consideration of the government's motion to extend stay of the mandate pending filing and disposition of petition for a writ of certiorari and the response thereto, it is ORDERED that the motion be granted. The Clerk is directed to withhold issuance of the mandate through January 15, 2015. If within the period of stay, respondent notifies the Clerk in writing that a petition for writ of certiorari has been filed, the Clerk is directed to withhold issuance of the mandate pending the Supreme Court's final disposition. [1526083-2] Before Judges: Brown, Edwards and Silberman. [11-1486, 11-1489, 12-1088, 12-1091, 12-1093]

UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 35

Docket No. RM10-17-000

DEMAND RESPONSE COMPENSATION IN ORGANIZED WHOLESALE ENERGY MARKETS

Docket No. EL09-68-000

PJM INTERCONNECTION, L.L.C.

Mar. 18, 2010

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is issuing a Notice of Proposed Rulemaking (NOPR) proposing an approach for compensating demand response resources in order to improve the competitiveness of organized wholesale energy markets and thus ensure just and reasonable wholesale rates. The Commission invites all interested persons to submit comments in response to the regulatory text proposed herein.

DATES: Comments are due 45 days after publication in the Federal Register.

ADDRESSES: You may submit comments, identified by docket number by any of the following methods:

- Agency Web Site: http://ferc.gov. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format.
- Mail/Hand Delivery: Commenters unable to file comments electronically must mail or hand deliver an original and 14 copies of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, N.E., Washington, DC 20426.

Instructions: For detailed instructions on submitting comments and additional information on the rulemaking process, see the Comment Procedures Section of this document.

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SUPPLEMENTARY INFORMATION:

UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. RM10-17-000

DEMAND RESPONSE COMPENSATION IN ORGANIZED
WHOLESALE ENERGY MARKETS

Docket No. EL09-68-000

PJM INTERCONNECTION, L.L.C.

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NOTICE OF PROPOSED RULEMAKING

TABLE OF CONTENTS

Paragraph Numbers

I. Background ..... [24]
  A. Role of Demand Response in Organized Wholesale Energy Markets ..... [24]
  B. Current ISO and RTO Demand Response Programs ..... [29]
  C. The Need for Reform ..... [32]
II. Discussion ..... [34]
III. Information Collection Statement ..... [43]
IV. Environmental Analysis ..... [46]
V Regulatory Flexibility Act Certification ..... [48]
VI. Comment Procedures ..... [49]
VII. Document Availability ..... [50]

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1. The Federal Energy Regulatory Commission (Commission) is proposing to revise its regulations to establish the approach described below as compensation for demand response[1] resources[2] participating in organized energy markets. We propose that Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs)[3] with tariff provisions permitting

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[1] Demand response means a reduction in the consumption of electric energy by customers from their expected consumption in response to an increase in the price of electric energy or to incentive payments designed to induce lower consumption of electric energy. 18 CFR § 35.28 (b)(4).

[2] Demand response resource means a resource capable of providing demand response. 18 CFR § 35.28 (b)(5).

[3] The following RTOs and ISOs have organized wholesale electricity markets: PJM Interconnection, L.L.C. (PJM); New York Independent System Operator, Inc. (NYISO); Midwest Independ-

demand response providers to participate as resources in energy markets by reducing consumption of electricity from their expected levels in response to price signals be required to pay to demand response providers, in all hours, the market price for energy for such reductions.[4]

I. Background

A. Role of Demand Response in Organized Wholesale Energy Markets

2. The Commission has acted over the last several decades to implement Congressional policy to expand the wholesale energy markets to facilitate entry of new resources and support competitive markets. Most recently, the Commission in Order No. 719 implemented a series of reforms aimed at improving the competitiveness of the organized energy markets, finding that effective whole-

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ent Transmission System Operator, Inc. (Midwest ISO); ISO New England, Inc. (ISO-NE); California Independent System Operator Corp. (CAISO); and Southwest Power Pool, Inc. (SPP).

[4] This provision applies only to demand response acting as a resource in organized wholesale energy markets. The provision will not apply to demand response under programs that ISOs and RTOs administer for reliability or emergency conditions, such as, for instance, Midwest ISO's Emergency Demand Response; NYISO's Emergency Demand Response Program; PJM's Emergency Load Response; and ISO-NE's Real-Time 30-Minute Demand Response Program, Real-Time and 2-Hour Demand Response Program, and Real-Time Profiled Response Program. This provision also will not apply to compensation in ancillary services markets, which the Commission has addressed elsewhere. *See e.g., Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, 73 Fed. Reg. 64,100 (Oct. 28, 2008), FERC Stats. & Regs. P 31,281 (2008) (Order No. 719 or Final Rule).

sale competition protects consumers by, among other things, providing more supply options, encouraging new entry and innovation, and spurring deployment of new technologies.[5] Improving the competitiveness of organized wholesale markets, the Commission concluded, is therefore "integral to the Commission fulfilling its statutory mandate to ensure supplies of electric energy at just, reasonable, and not unduly discriminatory or preferential rates."[6]

3. As the Commission recognized in Order No. 719, active participation by customers in organized wholesale energy markets through demand reductions helps to increase competition in those markets.[7] Demand reductions whereby customers reduce electricity consumption from normal usage levels in response to price signals can generally occur in two ways: (1) customers reduce demand by responding to dynamic rates that are based on wholesale prices (sometimes called "price-responsive demand"); and (2) customers can provide demand response that acts as a resource in wholesale markets to balance supply and demand. While a number of states and utilities are pursuing retail-level price-responsive demand initiatives based on dynamic and time differentiated retail prices and utility investments, these are state initiatives, and, thus, are not the subject of this proceed-

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[5] *See* Order No. 719 at P 1; *see also Regional Transmission Organizations*, Order No. 2000, FERC Stats. & Regs. ¶ 31,089, at P 1 (1999), *order on reh'g*, Order No. 2000-A, FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom. Pub. Util. Dist. No. 1 of Snohomish County, Washington v. FERC*, 272 F.3d 607, 348 U.S. App. D.C. 205 (D.C. Cir. 2001).

[6] Order No. 719 at P 1.

[7] *See* Order No. 719 at P 48.

ing.[8] Our focus here is on customers providing—through bids—demand response that acts as a resource in organized wholesale energy markets.

4. Demand response acting as a resource in organized wholesale energy markets helps to improve the functioning and competitiveness of such markets in several ways. First, demand response can lower prices. When bid directly into the wholesale market, demand response—which results in lower demand—can result in lower clearing prices.[9] For example, a study conducted by PJM, which simulated the effect of demand response on prices, demonstrated that a modest three percent load reduction in the 100 highest peak hours corresponds to a price decline of six to 12 percent.[10] Demand response can also lower prices in the organized wholesale energy markets by reducing the need to dispatch higher-priced generation, or construct new generation, in an effort to satisfy load.[11] Second, demand response can mitigate gen-

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[8] Some ISOs and RTOs are engaged in stakeholder discussions concerning the coordination necessary between wholesale markets and retail rate design, and we expect to address any filings emerging from those discussions in future proceedings.

[9] *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292 (2009).

[10] ISO-RTO Council Report, Harnessing the Power of Demand How ISOs and RTOs Are Integrating Demand Response into Wholesale Electricity Markets, found at http://www.isorto.org/atf/cf/%7B5B4E85C6-7EAC-40A0-8DC3-003829518EBD%7D/IRC_DR_Report_101607.pdf.

[11] *Id.* ("Demand response tends to flatten an area's load profile, which in turn may reduce the need to construct and use more costly resources during periods of high demand; the overall effect is to lower the average cost of producing energy."). Similarly, NYISO "has experienced a significant increase in the registration of the [demand response] programs that have effectively reduced the

erator market power.[12] This is because the more demand response is able to reduce demand, the more downward pressure it places on generator bidding strategies by increasing the risk to a supplier that it will not be dispatched if it bids a price that is too high.[13] Third, demand response has the potential to support system reliability and address resource adequacy[14] and resource

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need for additional [generation] capacity resources to the system based on customer pledges to cut energy usage on demand." *See* NYISO's 2009 Comprehensive Reliability Plan at 3, found at http://www.nyiso.com/public/webdocs/newsroom/planning_reports/CRP_FINAL_5-19-09.pdf.

[12] *See* Comments of NYISO's Market Monitor filed in Docket No. ER09-1142-000, May 15, 2009 (Demand response "contributes to reliability in the short-term, resource adequacy in the long-term, reduces price volatility and other market costs, and mitigates supplier market power.").

[13] *Id.*

[14] *See* ISO-RTO Council Report, Harnessing the Power of Demand How ISOs and RTOs Are Integrating Demand Response into Wholesale Electricity Markets at 4, found at http://www.isorto.org/atf/cf/%7B5B4E85C6-7EAC-40A0-8DC3-003829518EBD%7D/IRC_DR_Report_101607.pdf ("Demand response contributes to maintaining system reliability. Lower electric load when supply is especially tight reduces the likelihood of load shedding. Improvements in reliability mean that many circumstances that otherwise result in forced outages and rolling blackouts are averted, resulting in substantial financial savings. "); *Smart Grid Policy*, 126 FERC ¶ 61,253, at P 19 and n.23 (2009) ("The Smart Grid concept envisions a power system architecture that permits two-way communication between the grid and essentially all devices that connect to it, ultimately all the way down to large consumer appliances. . . Once that is achieved, a significant proportion of electric load could become an important resource to the electric system, able to respond automatically to customer-selected price or dispatch signals delivered over the Smart Grid infrastructure without significant degradation of service quality.").

management challenges surrounding the unexpected loss of generation.[15]

5. Given its ability to lower electricity prices and ensure reliability, demand response can play a critical role in helping the Commission fulfill its mandate under the Federal Power Act (FPA) to ensure that rates charged for energy are just and reasonable.[16] Accordingly, and consistent with national policy requiring facilitation of demand response,[17] the Commission has acted to remove barriers to participation of demand response resources in organized wholesale electricity markets. For example, in Order No. 890, the Commission modified the *pro forma* Open Access Transmission Tariff to allow non-generation resources, including demand response resources, to be used in the provision of certain ancillary services where appropriate on a comparable basis to service provided by generation resources.[18] Order No. 890-A further re-

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[15] For instance, in ERCOT, on February 26, 2008, through a combination of a sudden drop in power supplied by wind generators, a quicker-than-expected ramping up of demand, and the loss of thermal generation, ERCOT found itself short of reserves. The system operator called on all demand response resources, and 1200 MW of Load acting as Resource (LaaRs) responded within ten minutes, bringing ERCOT back into balance, from 59.85 Hz back to 60 Hz.

[16] 16 U.S.C. § 824d (2006).

[17] *See EPAct 2005*, Pub. L. No. 109-58, § 1252(f), 119 Stat. 594, 965 (2005) ("It is the policy of the United States that . . . unnecessary barriers to demand response participation in energy, capacity, and ancillary service markets shall be eliminated.").

[18] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 887-88 (2007), *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g and clarification*, Order No. 890-B, 73 Fed. Reg. 39092 (Jul. 8, 2008), 123 FERC ¶ 61,299 (2008),

quires transmission providers to develop transmission planning processes that treat all resources, including demand response, on a comparable basis.[19]

6. The Commission built on these reforms in Order No. 719, requiring ISOs and RTOs to, among other things, accept bids from demand response resources in their markets for certain ancillary services on a basis comparable to other resources.[20] The Commission also required each ISO and RTO "to reform or demonstrate the adequacy of its existing market rules to ensure that the market price for energy reflects the value of energy during an operating reserve shortage,"[21] for purposes of encouraging existing generation and demand resources to continue to be relied upon during an operating reserve shortage, and encouraging entry of new generation and demand resources.[22]

B. Current ISO and RTO Demand Response Programs

7. In addition to the foregoing efforts, the Commission has issued orders in recent years approving various types of ISO and RTO demand response programs. As noted above, some of these programs are administered for reliability and emergency conditions. Apart from these programs, wholesale customers and qualifying large retail customers may bid demand response directly into the day-ahead and real-time energy markets, certain ancil-

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order on reh'g, Order No. 890-C, 126 FERC ¶ 61,228 (2009), *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

[19] Order No. 890-A at P 216.

[20] Order No. 719 at P 47-49.

[21] *Id.* P 194.

[22] *Id.* P 247.

lary service markets and capacity markets.[23] Demand response providers participating as resources in the day-ahead and real-time energy markets are the subject of this proceeding.

8. With particular regard to demand response compensation for this latter category of resources, the Commission previously has allowed a system-by-system approach, whereby each RTO and ISO has developed its own compensation methodologies for demand response resources in its energy market. As a result, the levels of compensation for demand response vary significantly among RTOs and ISOs. PJM pays the Locational Marginal Price (LMP)[24] minus the generation and transmission portions of the retail rate.[25] ISO-NE and NYISO

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[23] Other demand response programs allow demand response to be used as a capacity resource and as a resource during system emergencies or permit the use of demand response for synchronized reserves and regulation service. *See, e.g., PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331 (2006); *Devon Power LLC*, 115 FERC ¶ 61,340, *order on reh'g*, 117 FERC ¶ 61,133 (2006), *appeal pending sub nom., Maine Pub. Utils. Comm'n v. FERC*, No. 06-1403 (D.C. Cir. 2007); *New York Indep. Sys. Operator., Inc.*, 95 FERC ¶ 61,136 (2001); *NSTAR Services Co. v. New England Power Pool*, 95 FERC ¶ 61,250 (2001); *New England Power Pool and ISO New England, Inc.*, 100 FERC ¶ 61,287, *order on reh'g*, 101 FERC ¶ 61,344 (2002), *order on reh'g*, 103 FERC ¶ 61,304, *order on reh'g*, 105 FERC ¶ 61,211 (2003); *PJM Interconnection, L.L.C.*, 99 FERC ¶ 61,227 (2002).

[24] LMP refers to the price calculated by the ISO or RTO at particular locations or electrical nodes within the ISO or RTO footprint and is used as the market price to compensate generators. There are variations in the way ISOs and RTOs calculate LMP; however, each method establishes the marginal value of resources in that market. Nothing in this NOPR is intended to change ISO and RTO methods for calculating LMP.

[25] PJM FERC Electric Tariff, Sixth Revised Sheet No. 388D.01.

currently pay LMP when prices are above a threshold level, with the levels differing between the RTOs.[26] The Midwest ISO currently has a program that pays LMP for demand response in the real-time energy market when the demand response provider has purchased the amount reduced in the day-ahead market for energy and ancillary services.[27] CAISO pays LMP in its participating load program that allows qualifying resources to provide day-ahead and real-time energy and non-spinning reserves.[28] SPP currently has no demand response program at all.[29] ISOs and RTOs have continued to examine

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[26] For example, under ISO-NE's Real Time Price Response Program, the minimum bid is $100/MWh and a demand response resource is paid the higher of LMP or $100/MWh. *See* Section III.1.3 of the ISO New England Transmission, Markets and Services Tariff, Section 1 of the Second Restated New England Power Pool Agreement. NYISO implements a day-ahead demand response program by which resources bid into the market at a minimum of $75/MWh and can get paid the LMP. *See* NYISO Incentivized Day-Ahead Economic Load Curtailment Program, Fifth Revised Tariff Sheet No. 34-34A, 89.

[27] *See* Charges and Credits for Real-Time Energy and Operating Reserve Market Energy Purchases and Sales Associated with Demand Response Resources. Midwest ISO FERC Electric Tariff, Fourth Revised Volume No. 1, Second Revised Sheet No. 1114.

[28] *See* section 11.2.1.1 IFM Payments for Supply of Energy, CAISO FERC Electric Tariff.

[29] However, the Commission has directed SPP to report on ways it can incorporate demand response into its imbalance market. *Southwest Power Pool, Inc.*, 114 FERC ¶ 61,289, at P 229 (2006). In its orders addressing SPP's compliance with Order No. 719, the Commission also directed SPP to make a subsequent compliance filing addressing demand response participation in its organized markets. *Southwest Power Pool, Inc.*, 129 FERC ¶ 61,163, at P 51 (2009).

the effectiveness of demand response compensation in their respective regions, and, as a result, the issue of proper compensation continues to be the subject of several proceedings.[30]

C. The Need for Reform

9. Despite the benefits of demand response and various efforts by the Commission, ISOs and RTOs to address barriers to and compensation for demand response participation, demand response providers collectively play a small role in wholesale markets. After several years of observing demand response participation in ISO and RTO markets with different, and often evolving, demand response compensation structures, the Commission is concerned that some existing, inadequate compensation structures have hindered the development and use of demand response. The impediment has been addressed at Commission-sponsored technical conferences concerning demand response, where participants have confirmed that customers "must have confidence that appropriate price signals will be sustained by stable competitive pricing structures, before they will make an investment in demand response."[31] Some participants have advised

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[30] *See PJM Interconnection, L.L.C.*, Docket No. EL09-68-000; *ISO New England, Inc.*, Docket No. ER09-1051-000; *ISO New England, Inc.*, Docket No. ER08-830-000; *Midwest Indep. Transmission Sys. Operator, Inc.*, Docket No. ER09-1049-000.

[31] Transcript of Order No. 719 technical conference at 24, statement by James Eber, Director of Demand Response at Commonwealth Edison, found at http://www.ferc.gov/EventCalendar/EventDetails.aspx?ID=3994&CalType=%20&CalendarID=116&Date=05/21/2008&View=Listview.

that demand response quite simply will not occur without adequate compensation.[32]

10. Indeed, there are indications that demand response resources react correspondingly to increases or decreases in payment. PJM provides a case study on this point. It first implemented its Economic Load Response Program (Economic Program) providing for demand response compensation in June 2002.[33] Several years later, starting in January 2008, when PJM reduced its compensation for demand response, settled demand reductions began decreasing from previous years.[34] Specifically, PJM's Market Monitor noted that, from 2007 to 2008, following the decrease in compensation, settled demand reductions decreased by 36.8 percent, from 714,200 MWh to 458,300 MWh, and the decline has continued at least through March 2009.[35] Although the Commission had rejected a

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[32] *See* Statements of Larry Stalica, Vice President, Linde Energy Services, Inc. FERC Technical Conference-Demand Response in Organized Electric Markets, May 21, 2008, found at http://www.ferc.gov/EventCalendar/Files/20080521081612-Stalica,%20Linde%20Energy%20Services.pdf. ("The mere avoidance of electricity prices often provides insufficient value to offset these real costs. Demand response will not occur if customers do not have an economic incentive to reduce consumption.").

[33] *See PJM Interconnection, L.L.C.*, 99 FERC ¶ 61,227 (2002). PJM's Economic Program provided for payment of LMP for all demand response reductions when LMP equaled or exceeded $75/MWh and paid LMP minus the generation and transmission components of the retail rate when LMP was less than $75/MWh.

[34] The tariff provision providing for payment of LMP when LMP equaled or exceeded $75/MWh terminated by its terms on December 31, 2007, and, since then, PJM has paid only LMP minus the generation and transmission components of the retail rate.

[35] Monitoring Analytics, Barriers to Demand Side Response in PJM at 22 (July 1, 2009).

request to prevent the compensation decrease from occurring as per the terms of PJM's then-existing tariff, the Commission encouraged PJM and its stakeholders to continue analyzing the effectiveness of PJM's demand response program with the decreased payments for demand response.[36] Based upon our own review, the Commission is now concerned that evidence of demand reductions in PJM, and inadequate demand response participation , now and in the future, may be the result of compensation that is no longer just and reasonable, because, as detailed below, the existing and varying levels of compensation generally fail to reflect the marginal value of demand response resources to ISO and RTO energy markets.

II. Discussion

11. Given the importance of demand response resources to the competitiveness of organized wholesale electricity markets, and based upon our experience to date with demand response in the ISO- and RTO-administered markets, the Commission proposes to address compensation for demand response resources participating in organized wholesale energy markets generically in this proceeding. The Commission proposes to add section 35.18(g)(1)(v) to our regulations to establish a specific compensation approach for demand response resources participating in organized wholesale energy markets (such as the day-ahead and real-time markets administered by the ISOs and RTOs). Under the proposed section, each Commission-approved ISO and RTO that has a tariff provision providing for participation of demand response resources

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[36] *PJM Interconnection, L.L.C.*, 121 FERC ¶ 61,315, at P 29 (2007).

in its energy market must pay demand response resources, in all hours, the market price for energy, i.e., full LMP, for demand reductions made in response to price signals.[37]

12. The Commission proposes to take this action generically to address issues that are common to the RTO and ISO markets in a coordinated manner in a single proceeding. As discussed further below, we believe paying demand response resources the LMP in all hours will compensate those resources in a manner that reflects the marginal value of the resource to each RTO and ISO, comparable to treatment of generation resources. This will improve the competitiveness of the organized wholesale energy markets and, in turn, help to ensure that energy prices in those markets are just and reasonable.

13. As explained above, we have previously accepted a variety of ISO and RTO proposals for compensation for demand response providers, with different levels of payment. As we have gained experience with these programs, we are concerned that the current compensation levels appear to have become unjust and unreasonable. Providers may submit price and quantity bids into the organized wholesale energy markets and the market clears at the marginal resource yet they fail to compensate demand response at levels that reflect the marginal value of the resource being used by the RTO or ISO to balance supply and demand. The current wholesale compensation levels may therefore be leading to un-

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[37] This provision will not apply to programs that ISOs and RTOs administer for reliability or emergency conditions. In those situations, the ISO and RTO tariffs may provide compensation that is not necessarily related solely to energy prices but is designed to prevent involuntary load curtailment.

der-investment in demand response resources, resulting in higher, and unjust and unreasonable, prices in the organized electricity markets. To help ensure that wholesale prices in ISOs and RTOs remain just and reasonable, we are proposing to require each ISO and RTO to pay the LMP to demand response providers participating in the organized wholesale energy markets.

14. It is a well-established practice in the organized wholesale energy markets to rely on LMPs to encourage efficient behavior by market participants. The LMP represents the value of additional supply or reductions in consumption at each node within the RTO or ISO and, thus, reflects the marginal cost of the last unit necessary to efficiently balance supply and demand.[38] The LMP is therefore the primary mechanism for compensating generation resources clearing in the organized electricity markets, which the Commission has found encourages "more efficient supply and demand decisions in both the short run and long run."[39]

15. Given that the LMP represents the marginal value of the resource being used by the RTO or ISO to balance supply and demand, it follows that the LMP should be paid to any resource clearing in the RTO's or ISO's en-

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[38] *See ISO New England, Inc.*, 100 FERC ¶ 61,287, at P 71 (2002) (LMP "provide[s] appropriate price signals indicating the value of additional resources or conservation at each node in the transmission system"); *Cleco Power LLC, et al.*, 103 FERC ¶ 61,272, at P 67 (2003) ("It is widely observed that markets work efficiently when prices reflect marginal costs, i.e., when the market price will be equal to the cost of bringing to market the last unit necessary to balance supply and demand.").

[39] *See New England Power Pool*, 101 FERC ¶ 61,344, at P 35 (2002).

ergy market. In balancing supply and demand, a one megawatt reduction in demand is equivalent to a one megawatt increase in energy for purposes of meeting load requirements and maintaining a reliable electric system. The ISO or RTO is able to avoid dispatching suppliers with higher bids, be they generation or demand response, by accepting a lower bid to either reduce consumption or increase generation. As Dr. Alfred E. Kahn noted in a recent *PJM* proceeding in Docket No. EL09-68-000, consumers offering to reduce consumption should be induced "to behave as they would if the market mechanisms alone were capable of rewarding them directly for efficient economizing."[40] This is because "the (incremental) costs saved by curtailments in demand clearly will be LMP—including the marginal costs of generation. So, in the end the LMP inducement is the economically correct one."[41] This appears to be true across all ISOs and RTOs and, therefore, it appears appropriate to compensate both generation and demand response resources participating in the organized wholesale electricity markets at the LMP.

16. Ultimately, the markets themselves will determine the level of generation and demand response resources needed to balance energy and demand. The level of compensation provided to each resource, however, affects its willingness and ability to participate in the market.[42] For example, demand response resources need to make investments in technologies to enable participation in the

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[40] Kahn Affidavit at 4.

[41] *Id.* at 3.

[42] Generation and demand response resources have the potential to earn other revenues through bilateral arrangements, capacity markets where they exist, and ancillary services.

organized wholesale energy markets, as well as incur costs in changing their operations in order to provide demand response. In those markets paying less than the LMP to demand response resources, such resources have less revenues to support investment in demand response-enabling technology (such as metering equipment, energy usage monitors and process controls) necessary to enable more wholesale market participation by demand response resources. Where compensation for demand response is inadequate, demand response resources will be hesitant to invest in demand response devices. Compared to existing compensation levels, paying the LMP in all hours should allow more demand response resources to cover their investment costs and increase their ability to participate in the organized wholesale electric markets.

17. Increased levels of demand response participation, in turn, should lead to lower clearing prices in the organized wholesale energy markets. As the Commission explained in accepting PJM's Economic Load Response Program:

> Without a demand response mechanism, [an independent system operator] is forced to work under the assumption that all customers have an inelastic demand for energy and will pay any price for power. There is ample evidence that this is not true. Many customers, given the right tools, can and will manage their demand. A working demand response program puts downward pressure on price, because suppliers have additional incentives to keep bids close to their marginal production costs and high supply bids are more likely to reduce the bidder's energy sales. Appropriate price signals to customers thus helps to mitigate market power as

high supply bids are more likely to reduce the bidders' energy sales. Suppliers thus have additional incentive to keep bids close to their marginal production costs.[43]

18. Additionally, increasing the aggregate amount of demand response resources in the organized wholesale energy markets will help to move prices closer to the levels that would result if all demand could respond to the marginal cost of energy. Paying the LMP to those potential demand response resources who are capable of responding —but who have not been participating as a resource due to inadequate compensation—should bring those additional demand response resources into the organized wholesale energy markets. But again, the markets themselves will determine the appropriate level of demand response, and generation, resources needed by the ISO and RTO to balance energy and demand based on their relative bids into the markets.

19. We recognize that the appropriate level of compensation for demand response resources participating in organized wholesale energy markets has been the subject of debate. In various proceedings, some parties have advocated payment of LMP minus components of the retail rate, on the theory that such an approach permits all consumers to react as if they were paying LMP.[44] Some

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[43] *PJM Interconnection, L.L.C.*, 99 FERC ¶ 61,227, at 61,939 (2002) (quoting *PJM Interconnection, L.L.C.*, 99 FERC ¶ 61,139, at 61,573 (2002)).

[44] Professor William W. Hogan has argued, for instance, that payment of LMP (without an offset for some portion of the retail rate) over-compensates individual demand response providers and might result in more demand response than is efficient. *See* Attachment to Answer of Electric Power Supply Association, Providing Incen-

parties have argued that payment of LMP is appropriate only during the most expensive hours,[45] on the theory that demand response will have the greatest impact during those hours in which the aggregate supply curve is steep (*i.e.*, when supply is less elastic). Given the current barriers to demand response[46] and the evolving nature of the technology enabling demand response, a perfect solution or payment scheme may not exist. We nonetheless believe that paying LMP in all hours to the demand response resources that can participate in the organized wholesale energy markets is the correct approach at this time, because that payment reflects the marginal effect of each demand response resource in the hour, just as the LMP reflects the marginal effect of generation resources in each hour. LMP is the marginal value of both demand response and generation in any hour, regardless of

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tives for Efficient Demand Response, William W. Hogan, October 29, 2009, submitted in Docket No. EL09-68-000.

[45] *See* PJM's Transmittal Letter at 29 submitted in Docket No. EL09-68-000.

[46] A recent Commission Staff report details several barriers to demand response, including regulatory barriers, such as lack of a direct connection between wholesale and retail prices, lack of dynamic prices, measurement and verification challenges, lack of real-time information sharing, and ineffective demand response program design; technological barriers, such as lack of advanced metering infrastructure and the high cost of some enabling technologies; and other barriers, such as lack of customer awareness and education. Federal Energy Regulatory Commission Staff, A National Assessment of Demand Response Potential (June 2009), found at http://www.ferc.gov/legal/staff-refports/06-09-demand-response.pdf. In compliance filings submitted by RTOs and ISOs and their market monitors pursuant to Order No. 719, as well as in responsive pleadings, parties have mentioned additional barriers, such as the inability of demand response resources to set LMP, minimum size requirements, and others.

whether it is morning or evening, daytime or nighttime, weekday or weekend.[47]

20. We, nevertheless, seek comment on the need to compensate demand response acting as a resource in organized wholesale energy markets. Commenters may address whether current compensation for demand response providers acting as a resource in the organized wholesale energy markets is adequately procuring demand response. We further solicit comment on alternative approaches to compensating demand response resources participating in organized wholesale energy markets, and the merit of those approaches in comparison to the one proposed here. In particular, we ask for comment on whether a reduction in consumption is comparable to an increase in electricity production for purposes of balancing supply and demand, and whether, therefore, demand response providers and generators should receive comparable compensation. We further seek comment on whether paying LMP to demand response resources is comparable compensation or is more or less than comparable to compensation paid to generation in the ISO and RTO energy markets. We also request comment on whether payment of LMP should apply to all hours, and, if not, the criteria that should be used for establishing the hours when LMP should apply. Additionally, we seek comment on whether requiring payment of LMP is appropriate across all ISOs and RTOs, or

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[47] We note that in PJM, 17 percent of load reductions by demand response resources for that year occurred between the non-peak hours of 11 p.m. and 8 a.m. *See* 2008 State of the Market Report for PJM, Volume 2, Table 2-93 at 103, found at http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2008/2008-sompjm-volume2.pdf.

whether variations among ISOs and RTOs justify varying levels of demand response resource compensation. To that end, we further seek comment on whether the Commission should allow regional variations for an ISO or RTO that does not seek to compensate demand response resources participating in the organized wholesale energy market.

21. Organized wholesale energy markets are evolving and, as such, the rules and regulations related to those markets will continue to evolve. This is no less so for demand response, as the markets, and the types of demand response participating in them, continue to evolve. Therefore, it may be necessary in the future for industry and the Commission to reassess the appropriate method for compensating demand response resources in organized wholesale energy markets.[48] Accordingly, we also seek comment on whether, and under what circumstances, the Commission should conduct periodic reviews of demand response compensation and the criteria that should be used in making such assessments.

22. With specific regard to the proposed regulatory text set forth below, we seek comments on whether terms such

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[48] Indeed, the Commission's proposed action in this proceeding is evidence of our continuing assessment of compensation for demand response resources. In *PJM Interconnection, L.L.C.*, 121 FERC ¶ 61,315 (2007), the Commission rejected a complaint that PJM's existing compensation for demand response (LMP minus the generation and transmission components of the retail rate) was unjust and unreasonable, finding that there was insufficient evidence at the time to make such a finding. As we have acquired more experience with the participation of demand response resources in the organized wholesale energy markets, we are concerned that compensation for demand response in PJM and other RTO and ISO markets may no longer be just and reasonable.

as "expected levels," "price signals," and "market prices" are sufficiently defined.

23. Because we are addressing generically in this rulemaking proceeding the same issues raised in the *PJM* proceeding in Docket No. EL09-68-000, that docket is hereby terminated.[49] The Commission will take administrative notice of the record in the *PJM* proceeding so that parties in that proceeding need not refile affidavits or other evidence introduced there.

III. Information Collection Statement

24. The Office of Management and Budget (OMB) requires that OMB approve certain information collection and data retention requirements imposed by agency rules.[50] Therefore, the Commission is submitting the proposed modifications to its information collections to OMB for review and approval in accordance with section 3507(d) of the Paperwork Reduction Act of 1995.[51]

25. The Office of Management and Budget's (OMB) regulations require approval of certain information collection requirements imposed by agency rules. Upon approval of a collection(s) of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of a rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

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[49] *See Michigan Pub. Power Agency v. Midwest Indep. Transmission Sys. Operator, Inc.*, 128 FERC ¶ 61,268, at P 29 n.47 (2009) (Commission has discretion to decide when and where it will resolve an issue).

[50] 5 CFR § 1320.11(b) (2009).

[51] 44 U.S.C. § 3507(d) (2006).

26. The Commission is submitting these reporting requirements to OMB for its review and approval under section 3507(d) of the Paperwork Reduction Act. Comments are solicited on the Commission's need for this information, whether the information will have practical utility, the accuracy of provided burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected, and any suggested methods for minimizing the respondent's burden, including the use of automated information techniques.

Burden Estimate: The Public Reporting burden for the requirements contained in the NOPR is as follows:

Data Collection	Number of Respondents	No. of Responses	Hours Per Response	Total Annual Hours
FERC-516				
Transmission Organizations with Organized Electricity Markets	6	1	6	36

Information Collection Costs: The Commission seeks comments on the costs to comply with these requirements. The Commission has projected the average annualized cost of all respondents to be the following: 36 hours @ $220 per hour = $7,920 for respondents. No capital costs are estimated to be incurred by respondents.

Title: FERC-516 "Electric Rate Schedule Tariff Filings"

Action: Proposed Collections.

OMB Control No: 1902-0096.

Respondents: Business or other for profit, and/or not for profit institutions.

Frequency of Responses: One time to initially comply with the rule, and then on occasion as needed to revise or modify.

27. Necessity of the Information: The information from FERC-516 enables the Commission to exercise its statutory obligation under Sections 205 and 206 of the FPA. FPA section 205 specifies that all rates and charges, and related contracts and service conditions for wholesale sales and transmission of energy in interstate commerce be filed with the Commission and must be "just and reasonable." In addition, FPA section 206 requires the Commission upon complaint or its own motion, to modify existing rates or services that are found to unjust, unreasonable, unduly discriminatory or preferential. The Commission needs sufficient detail to make an informed and reasonable decision concerning the appropriate level of rates, and the appropriateness of non-rate terms and conditions, and to aid customers and other parties who may wish to challenge the rates, terms, and conditions proposed by the utility.

28. This proposed rule, if adopted, would amend the Commission's regulations to obligate ISOs and RTOs to pay the market price for energy to demand response resources for demand reductions within each respective ISO and RTO region. Requiring ISOs and RTOs to pay the market price for energy to demand response resources for demand reductions in response to price signals will potentially reduce the market clearing price of electricity. The Commission has emphasized the importance of demand response as a vehicle for improving the competitiveness of organized wholesale electricity mar-

kets and ensuring supplies of energy at just, reasonable and not unduly discriminatory or preferential rates.[52]

29. Internal review: The Commission has reviewed the requirements pertaining to organized wholesale electric markets and determined the proposed requirements are necessary to its responsibilities under sections 205 and 206 of the FPA.

30. These requirements conform to the Commission's plan for efficient information collection, communication and management within the energy industry. The Commission has assured itself, by means of internal review, that there is specific, objective support for the burden estimates associated with the information requirements.

31. Interested persons may obtain information on the reporting requirements by contacting: Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426 [Attention: Michael Miller, Office of the Executive Director, Phone: (202) 502-8415, fax: (202) 273-0873, e-mail: michael.miller@ferc.gov]. Comments on the requirements of the proposed rule may also be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission], e-mail: oira_submission@omb.eop.gov.

IV. Environmental Analysis

32. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant

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[52] Order No. 719 at P 16.

adverse effect on the human environment.[53] The Commission concludes that neither an Environmental Assessment nor an Environmental Impact Statement is required for this NOPR under section 380.4(a)(15) of the Commission's regulations, which provides a categorical exemption for approval of actions under sections 205 and 206 of the FPA relating to the filing of schedules containing all rates and charges for the transmission or sale of electric energy subject to the Commission's jurisdiction, plus the classification, practices, contracts and regulations that affect rates, charges, classifications, and services.[54]

V. Regulatory Flexibility Act Certification

33. The Regulatory Flexibility Act of 1980 (RFA)[55] generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities.[56] ISOs and RTOs, not small entities, are impacted directly by this rule.

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[53] Order No. 486, *Regulations Implementing the National Environmental Policy Act*, 52 Fed. Reg. 47,897, FERC Stats. & Regs. Regulations Preambles 1986-1990 30,783 (1987).

[54] 18 CFR § 380.4(a)(15) (2009).

[55] 5 U.S.C. § 601-12 (2000).

[56] The RFA definition of "small entity" refers to the definition provided in the Small Business Act, which defines a "small business concern" as a business that is independently owned and operated and that is not dominant in its field of operation. *See* 15 U.S.C. § 601(3) (2000) (citing to section 3 of the Small Business Act, 15 U.S.C. § 632 (2000)). The Small Business Size Standards component of the North American Industry Classification system defines a small utility as one that, including its affiliates, is primarily engaged in the generation, transmission, or distribution of electric energy for sale, and whose total electric output for the preceding fiscal years did not exceed 4 MWh. 13 CFR § 121.202 (Sector 22,

34. California Independent System Operator Corp. (CAISO) is a non-profit organization comprised of more than 90 electric transmission-owning companies and generators operating in its markets and serving more than 30 million customers.

35. New York Independent System Operator, Inc. (NYISO) is a non-profit organization that oversees wholesale electricity markets serving 19.2 million customers. NYISO manages a 10,775-mile network of high-voltage lines.

36. PJM Interconnection, L.L.C. (PJM) is comprised of more than 450 members including power generators, transmission owners, electricity distributors, power marketers, and large industrial customers, serving 13 states and the District of Columbia.

37. Southwest Power Pool, Inc. (SPP) is comprised of 50 members serving 4.5 million customers in eight states and has 52,301 miles of transmission lines.

38. Midwest Independent Transmission System Operator, Inc. (Midwest ISO) is a non-profit organization with over 131,000 megawatts of installed generation. Midwest ISO has 93,600 miles of transmission lines and serves 15 states and one Canadian province.

39. ISO New England, Inc. (ISO-NE) is a regional transmission organization serving six states in New England. The system is comprised of more than 8,000 miles of highvoltage transmission lines and several hundred generation facilities, of which more than 350 are under ISO-NE's direct control.

Utilities, North American Industry Classification System, NAICS) (2004).

40. The Commission believes this rule will not have a significant economic impact on a substantial number of small entities, and therefore no regulatory flexibility analysis is required.

VI. Comment Procedures

41. The Commission invites interested persons to submit comments on the proposed regulatory text that commenters may wish to discuss. Comments are due 45 days after publication in the *Federal Register*. Comments must refer to Docket No. RM10-17-000,[57] and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

42. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's web site at http://www.ferc.gov. The Commission accepts most standard word processing formats. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format. Commenters filing electronically do not need to make a paper filing.

43. Commenters that are not able to file comments electronically must send an original and 14 copies of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE, Washington, DC 20426.

44. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not re-

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[57] Because this NOPR terminates Docket No. EL09-68-000, comments should not refer to that proceeding.

quired to serve copies of their comments on other commenters.

VII. Document Availability

45. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (http://www.ferc.gov) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington, DC 20426.

46. From FERC's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

47. User assistance is available for eLibrary and the FERC's web site during normal business hours from FERC Online Support at (202) 502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202) 502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

List of subjects in 18 CFR Part 35

Electric power rates, Electric utilities, Reporting and recordkeeping requirements. By direction of the Commission. Commissioner Moeller is concurring in part and dissenting in part with separate statement attached.

(SEAL)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

In consideration of the foregoing, the Commission proposes to amend Chapter I, Title 18 of the Code of Federal Regulations as follows:

PART 35—FILING OF RATE SCHEDULES AND TARIFFS

1. The authority citation for Part 35 continues to read as follows:

Authority: 16 U.S.C. § 791a-825r, 2601-2645; 31 U.S.C. § 9701; 42 U.S.C. § 7101-7352.

2. Amend § 35.28 as follows:

Add a new paragraph (g)(1)(v).

§ 35.28 Non-discriminatory open access transmission tariff.

* * * * *

(v) Demand response compensation in energy markets. Each Commission—approved independent system operator or regional transmission organization that has a tariff provision permitting demand response resources to participate as a resource in the energy market by reducing consumption of electric energy from their expected levels in response to price signals must pay to those demand response providers, in all hours, the market price for energy for these reductions.

UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. RM10-17-000

DEMAND RESPONSE COMPENSATION IN ORGANIZED WHOLESALE ENERGY MARKETS

Docket No. EL09-68-000

PJM INTERCONNECTION, L.L.C.

Issued: Mar. 18, 2010

MOELLER, Commissioner, *concurring, in part* and *dissenting, in part*:

As our country's demand for energy increases, the reduction of energy usage through demand response programs will play a critical role in meeting our needs and it is my hope that this nascent industry will thrive and succeed. In the Energy Policy Act of 2005, Congress established a policy to encourage the use of demand response by: (1) facilitating the deployment of technology to enable customers to participate in demand response programs; and (2) eliminating unnecessary barriers to demand response participation.[58] Even before this law was passed, this Commission supported similar policies in the organized electric markets by encouraging the use of

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[58] Energy Policy Act of 2005, Pub. L. No. 109-58 § 1252(f), 119 Stat. 594 (2005).

price responsive demand during high priced energy periods.[59]

Demand response is playing an increasingly critical role in our nation's energy supply mix. Additional demand response has the potential to produce more efficient market outcomes, contribute to a cleaner environment,[60] result in lower costs to customers, and help to check market power since it provides a countervailing willingness to reduce demand in the face of high prices.[61] With respect to prices, studies have shown that sometimes a small decrease in demand from demand response resources during peak periods can significantly reduce market prices. In sum, the benefits that demand response resources can bring to the energy markets are proven and significant.

The initial success of demand response has resulted in a steady maturation of the demand response industry. However, as the industry continues to mature, we must ensure that our policies are properly tailored to guide the development of demand response in a manner that will result in economically-efficient outcomes. Moving too quickly to reach a desired result can result in unintended consequences—and I believe that today's decision to pro-

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[59] *PJM Interconnection, L.L.C.*, 99 FERC ¶ 61,227, at 61,943 (2002), *see also* Order No. 719 at P 16 ("Thus, enabling demand-side resources . improves the economic operation of electric power markets by aligning prices more closely with the value customers place on electric power.").

[60] A recent report by the National Research Council, *Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use*, provides estimates of the cost associated with air pollution as the result of energy production.

[61] *California Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274, at P 689.

pose a standard payment could have unintentional effects on both demand response participation and the efficient operation of the organized markets over the longer term.

In today's notice of proposed rulemaking (NOPR), the majority concludes that the Commission should require a standard payment to compensate demand response resources. Specifically, the majority's proposed outcome would be that these resources are paid the market price (*i.e.*, the locational marginal price or "LMP") for energy reductions in all 8,760 hours of the year. This determination is followed by questions such as whether other compensation designs could also work; questions that I believe would have been more appropriately asked *prior* to establishing this NOPR.[62] For that reason, I believe that a preliminary issuance (such as a Notice of Inquiry) should have been established to collect and analyze the evidence in advance of initiating a formal rulemaking proceeding.

While the majority claims that it is "concerned that compensation for demand response in PJM and other RTO and ISO markets may no longer be just and reasonable", the NOPR lacks a thorough discussion of the evidence that they relied upon to substantiate their concerns.[63] The NOPR also lacks a sufficient explanation of

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[62] To the extent that this NOPR asks questions to determine whether the proposed rule is just and reasonable, I concur.

[63] NOPR at n.48. In support of the conclusion that compensation may no longer be just and reasonable, the preamble provides an example involving PJM's Economic Load Response Program and the drop of settled demand reductions experienced after the subsidy payments expired per the terms of PJM's tariff. NOPR at P 10. While the cited level of reduction is a fact, the PJM market monitor stated that "[w]hile the removal of the incentive program,

the "experience" that FERC has recently gained that would otherwise support the conclusion that the organized electric markets "fail to compensate demand response at levels that reflect the marginal value of the resource being used by the RTO or ISO to balance supply and demand."[64]

To the contrary, the record in Docket No. EL09-68-000 shows wide disagreement in the industry regarding the issue of demand response compensation. In that proceeding, state utility commissions[65], the grid operator, industry economists, and the market participants all reached various conclusions regarding the question of

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effective November 2007, may have reduced participation, the exact role of the elimination of the incentive program is not known because there were changes to other key factors which directly impact participation." *Citing* Monitoring Analytics, *Barriers to Demand Side Response* in PJM, at 22 (July 1, 2009). More recently, the PJM market monitor recognized that between 2008 and 2009, "[t]here were many factors contributing to the lower levels of participation and lower revenues in the Economic Program, including lower price levels in 2009, lower load levels, and improved measurement and verification." Notably, while payments from the Economic Program have fallen substantially since 2007, capacity revenue for demand response has increased significantly (rising 114% to $303 million from 2008 to 2009.) *Citing* Monitoring Analytics, *State of the Market Report for PJM*, at 111 (March 11, 2010).

[64] NOPR at P 13.

[65] Compare the position of the Indiana Utility Regulatory Commission (*i.e.*, LMP less the generation portion of retail rates (LMP-G) is an accepted indication of cost effectiveness) with the position taken by the New Jersey Board of Public Utilities and the District of Columbia Public Service Commission (*i.e.*, compensation for demand response should be based solely on LMP). Comments filed in Docket No. EL09-68-000.

how to compensate demand response resources in PJM.[66] In light of such rigorous debate, I am not sure if the Commission has a sustainable rationale to support a finding that the proposed rule is just and reasonable and that the existing compensation methods (that have been approved by this Commission) are no longer just and reasonable.

In fact, only recently did the Commission issue an order that not only sustained the manner by which PJM compensates demand response resources but also encouraged PJM and its stakeholders to identify and analyze issues to improve their demand response program.[67] Subsequently, PJM filed a detailed report explaining that while the stakeholder process did not yield a consensus position, the PJM Board moved forward and developed a compromise solution that was designed to strengthen its demand response markets.[68] In lieu of evaluating the merits of the proposal approved by PJM's Board, the

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[66] While there appears to be no disagreement that the correct price signal for all customers is the LMP, the debate centers on whether demand response resources should be *paid* the LMP *or* should realize the *value* of LMP if they choose to reduce demand. Additionally, at certain times, the LMP can become negative, meaning that generators must pay into the market to the extent they generate power. Should demand response resources likewise be required to pay into the market during negative LMP events, or should they be exempt?

[67] *PJM Industrial Customer Coalition v. PJM Interconnection, L.L.C.*, 121 FERC ¶ 61,315, at P 29 (2007) (Wellinghoff and Kelly, Comm'rs, dissenting).

[68] PJM did note that the concept of paying LMP-G received considerable support and "conservatively could be said to have garnered at least a three-quarters majority approval." *See* PJM Supplemental Report in Docket No. EL09-68-000 at 24-25.

NOPR terminates the PJM docket and directs PJM and its stakeholders to focus on whether demand response resources should be paid the market price—a question that has undoubtedly been analyzed, addressed and debated at numerous stakeholder meetings.

Since today's NOPR does not sufficiently explain the need for a uniform compensation approach, I am troubled by the decision to terminate PJM's individual proceeding. If approved, PJM's efforts toward developing a compromise solution for its market would have likely resulted in additional demand response participation and its associated benefits. However, with this NOPR's issuance, PJM and the other RTOs must now refrain from making changes to its demand response compensation rules pending the outcome of the rulemaking proceeding. The NOPR may also discourage some emerging organized markets from continuing to evolve toward the LMP model, as well as discourage some non-organized regions from seriously considering moving toward a market structure.

Ultimately, I want demand response to thrive and succeed in *all* the energy markets.[69] However, there are only so many policy decisions and rulemakings that this Commission can make to encourage its development. As

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[69] My concern here goes to highlight the differences between regions with competitive wholesale markets and those that consist of largely bilateral market structures. By imposing a uniform compensation requirement, this proposed rulemaking could further exacerbate bifurcated approach towards national policy: entities in a competitive wholesale market must comply with increasingly burdensome requirements while entities operating in bilateral markets are often free from requirements that otherwise advance national policy goals.

mentioned in the preamble, the primary barrier to increased demand response is the disconnect between retail and wholesale prices and the remedy resides at the retail level where there is a lack of dynamic pricing. The approach embraced in the NOPR may also lead to a situation where residential ratepayers could be subsidizing other classes of service while unable to participate themselves in demand response programs. Absent attention to these issues, it will be difficult for any proposal to place generation and demand response on a precisely level playing field.

Until then, this Commission must review what options it has available without resorting to policies that would adversely enable the short-term development of demand response at the expense of its longer-term success. In closing, I believe that demand response programs have great potential to enhance the organized energy markets and I look forward to their continued development. I am concerned, however, that a one-size-fits-all approach could result in uneconomic outcomes that ultimately set back the future development of demand response.

Philip D. Moeller
Commissioner

UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. RM10-17-000

DEMAND RESPONSE COMPENSATION IN ORGANIZED WHOLESALE ENERGY MARKETS

Docket No. EL09-68-000

PJM INTERCONNECTION, L.L.C.

May 6, 2010

COMMENTS OF THE ILLINOIS COMMERCE COMMISSION

Pursuant to the Federal Energy Regulatory Commission's ("Commission") Notice of Proposed Rulemaking ("NOPR") on Demand Response Compensation in Organized Wholesale Energy Markets[1], and the Notice issued in the Federal Register on March 18, 2010,[2] setting May 13, 2010 as the comment date, the Illinois Commerce Commission ("ICC") respectfully submits the following comments in the above-captioned dockets. The ICC believes that demand

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[1] *Demand Response Compensation in Organized Wholesale Energy Markets*, 130 FERC ¶ 61,213 (2010) (*hereinafter*, "NOPR").

[2] *Demand Response Compensation in Organized Wholesale Energy Markets*, DOE Notice, 75 Fed. Reg. 59, at 15362 (March 29, 2010).

response[3] resources[4] should be fairly compensated. These comments will show that the ICC supports the payment of LMP minus the retail rate for economic demand response in the wholesale market because it provides load serving entities with the right incentives to allow the participation of economic demand response resources. The ICC also comments on the relative efficiency between supply side demand response in wholesale markets and retail rate reform.

I. COMMENTS

The Commission's NOPR recognized a fundamental question concerning demand response compensation. "In particular, we [the Commission] ask for comment on whether a reduction in consumption is comparable to an increase in electricity production for the purposes of balancing supply and demand, and whether, therefore, demand response should receive comparable compensation."[5] The content of the NOPR operates under the assumption that the answers to these questions are yes and yes. The ICC will first address the question of comparability and then address the more practical matter of a compensation level.

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[3] The NOPR defines demand response as "a reduction in the consumption of electric energy by customers from their expected consumption in response to an increase in the price of electric energy or to incentive payments designed to induce lower consumption of electric energy." NOPR, at note 1, *citing* 18 C.F.R. § 35.28(b)(4).

[4] The NOPR defines demand response resource as "a resource capable of providing demand response." *Id.* at note 2, *citing* 18 C.F.R. § 35.28(b)(5).

[5] NOPR, P 20.

A. Comparability of Reductions in Consumption and Increases to Production

In pure economic terms a reduction in demand is fundamentally different from an increase in supply.[6] Demand reductions and supply increases are not only intuitively divergent, but treating them equivalently has material implications. Graphical depictions will be used to illustrate how demand reductions and supply increases affect the dispatch model and result in different market outcomes. The ICC believes that demand response should be incentivized and participants should be fairly compensated, but these comments show that they are not particularly comparable with generation supply.

The three graphics below show a market in equilibrium, demand response modeled as a demand reduction and demand response modeled as an increase to supply. The graphical depictions draw on the logic used in electricity dispatch and pricing algorithms employed in RTO markets. In these models, supply is an increasing function of quantity reflecting the increased willingness to supply additional energy as price increases. These models take the quantity of megawatts demanded as a fixed value at any one point in time. This fixed demand value is the constraint which drives the optimal dispatch of supply resources at that point in time. As such, demand will be illustrated as a vertical constraint by which the system operator optimizes the supply. In order to illustrate why reductions in consumption are not comparable to

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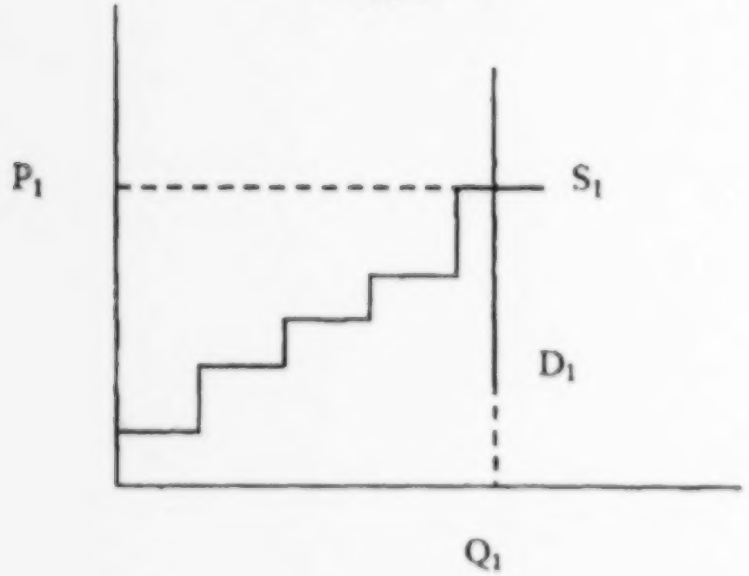
[6] *See* Verification form of Nicholas Bowden, Economic Analyst, Federal Energy Program, ICC, attached hereto at Appendix A, in support of the economic analysis for these comments.

increases in production we first assume an electricity market in equilibrium as shown in

Figure 1.

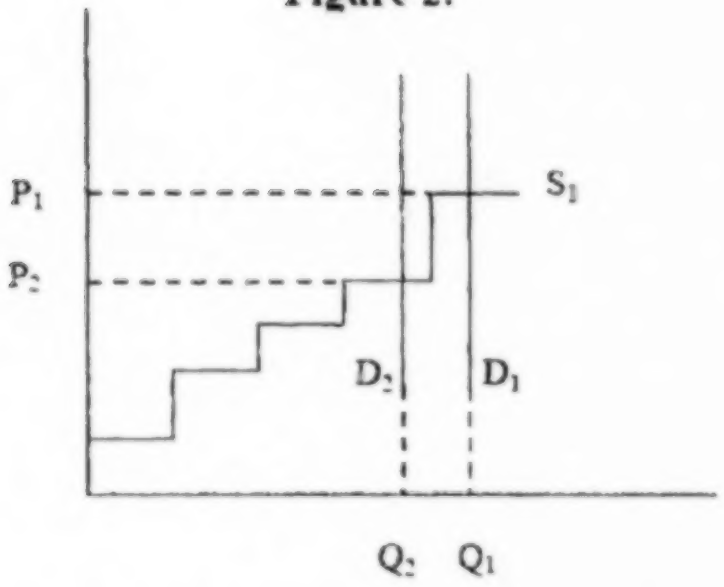
Figure 1.



Supply in the market is shown as a stepwise function, S_1, representing the output of generators and the prices at which they would provide that output, *i.e.* market bids. The demand in the market for this dispatch interval is shown as the vertical line D_1 at the quantity Q_1. The intersection of S_1 and D_1 for the given dispatch interval represented in Figure 1 determines the price, P_1.

Now, assume that consumption is reduced by the quantity equal to the difference between Q_1 and Q_2 in Figure 2 and assume that supply remains the same. In Figure 2 this reduction in consumption is modeled as a decrease in the fixed value of demand.

Figure 2.

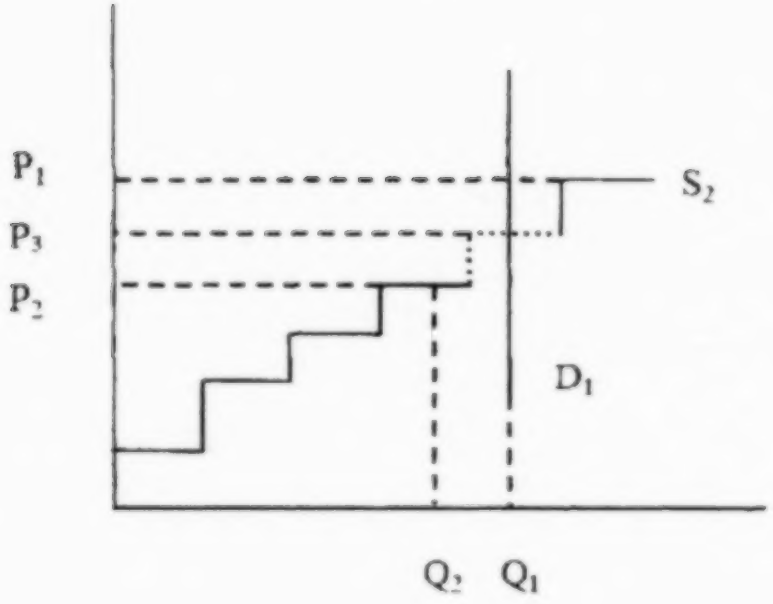


The new equilibrium is at the intersection of S_1 and D_2. The quantity cleared in the market and delivered as energy is Q_2. That quantity, Q_2, is cleared at the price of P_2. Total expenditure in the market is equal to the product of P_2 and Q_2. The reduction of load from Q_1 to Q_2 has resulted in a decrease in the price from P_1 to P_2. The customer who reduced demand avoids a cost equal to the locational marginal price ("LMP") or P1 multiplied by the quantity reduced, Q_1 minus Q_2. Also, all other customers face a lower price of P_2 and receive a benefit equal to the decrease in price, which is P_1 minus P_2, multiplied by the remaining demand Q_2. Figure 2 is an illustration of how supply and demand are balanced in a market when a reduction in consumption is an actual decrease in demand.

Now let us model the reduction in consumption as if it were an increase in supply and observe the market outcome. The graphical illustration in Figure 3 will

show the idea of demand reductions as a supply resource used to satisfy load. In Figure 3, demand will remain at the level associated with D_1 in the first model of equilibrium, Figure 1. Instead of modeling the demand response as a reduction in demand, Figure 3 will model the demand reduction as a supply resource representative of the way economic demand response resources participate in organized wholesale markets. Modeling a demand reduction this way produces a new supply curve, S_2. The dashed portion of the new supply curve is the demand response resource's demand reduction modeled as a supply offer for the quantity equal to that demand reduction, Q_1 minus Q_2 modeled in Figure 1. In order to obtain the effect of the economic demand response resources supply offer at the margin, the offer will be modeled so as to displace the marginal supply offer setting price in the equilibrium model in Figure 1.

Figure 3.



There are several outcomes to observe in Figure 3. Assuming the demand response resource can set price, then the market clearing price is P_3 which is less than the market clearing price, P_1, set in the original equilibrium, but greater than the price, P_2, that would have occurred if the reduction in consumption was an actual reduction in market demand.

When demand response is modeled as a supply resource, equivalent to generation, then the reduction in electrical consumption is not actually a reduction in demand. Therefore, the quantity cleared in the market place is still equal to Q_1 although the actual electrical consumption is reduced to Q_2. Total cost to consumers is equal to the product Q_1 and P_3, unambiguously greater that total cost in the actual demand reduction scenario depicted in Figure 2. It is also worth noting that the total cost in Figure 3 is less than

that in Figure 1, *i.e.* total cost in the market has been reduced from the level it was in the scenario depicted in Figure 1. However, the total quantity of consumption was also reduced and any productive output resulting from that quantity has been negated.

This reality is the source of the compensation issue discussed in the Commission's NOPR. No MWhs were consumed between Q_2 and Q_1, so the question is raised regarding what is being paid and what is it worth, and ultimately who is paying for it? Figures 1 through 3 should stand as a simple yet complete exposition of the inconsistency in comparing a reduction in consumption to an increase in electricity production.

B. Demand Response Compensation

The more pragmatic question asked by the Commission is whether demand response providers should receive the LMP when they are called upon to reduce consumption.[7] The Commission's NOPR proposes the payment of full LMP. In the simplest of terms, paying LMP to both generation and demand response in the wholesale market is not only comparable, but exactly equivalent. The difficulty is that demand response and generation resources are not comparable to begin with, and treating them as such in the wholesale market will result in inefficient market outcomes and have adverse implications for retail regulators. In order to provide the Commission with complete information about demand response and compensation, the ICC will discuss the nature and implications of the following three methods of compensation for demand

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[7] *Id.*

response: (1) zero; (2) LMP minus the retail rate; and (3) LMP.

1. Zero Payment

In theoretical terms a payment of zero dollars is the economically efficient compensation for reductions in demand in a marketplace. The incentive for demand to reduce consumption is the avoidance of paying the market price. The money a consumer avoids spending by reducing consumption of electricity can then be spent on consumption of other goods or the same good at another point in time. When the price of one good becomes high relative to all other goods, then the quantity consumed of the one becomes less relative to all the others. This is the basis of economic efficiency. This efficiency is consistent with, although not explicit, in the dissenting portion of Commissioner Moeller's comments in the sense that a world with dynamic retail rates would incent demand participation in a manner consistent with normal market behavior.[8] Actual demand side participation is fundamentally different than the supply side demand reductions currently contemplated in the Commission's NOPR.

The difficulty with incorporating demand in wholesale electric markets is the divergence between wholesale prices and retail rates. Because retail rates faced by the majority of consumers do not reflect wholesale rates at the time of consumption, there is no market price signal to consume differently at different times in the day. Because this condition is not consis-

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[8] NOPR, Commissioner Moeller, concurring in part and dissenting in part, at 5.

tent with the wholesale pricing structure, load serving entities developed compensation mechanisms to incent the reduction in demand at times when the load serving entity valued the reduction in demand for reliability's sake.

The RTO has gone one step further by allowing demand resources to choose the price level at which they are willing to reduce consumption for some incentive payment. The Commission has furthered the integration of demand response into the wholesale market by introducing aggregators of retail customers ("ARCs"). It is for these reasons that the Commission now contemplates the level of compensation that will provide the most value to society. The ICC agrees with Commission Moeller's statement that a "decision to propose a standard payment could have unintentional effects on both demand response participation and the efficient operation of the organized markets in the longer term."[9] Specifically, the Commission's decision to compensate demand response resources may tend to limit the incentive for retail rate reform in the form of exposure to wholesale spot energy prices.

The ICC affirms the principle that implementing dynamic retail rates would be a more effective mechanism to achieve the goal of efficient electrical resource utilization than would demand response resources participating through supply offers in wholesale markets. However, in the interim, it is best to recognize the efforts, while valuable, may fall short of retail rate reform, *i.e.* administrative constructs that are attemp-

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Id. at 2.

ting to mimic what would occur in truly price responsive markets. Furthermore, it is critical that these administrative constructs be designed so as to not create obstacles to a more fully realized demand participation in the market.

2. LMP minus Retail Rate Payment

Paying demand response resources LMP minus the retail rate has some intuitive appeal as well as strong economic underpinnings. A rational economic demand response resource would not curtail load until the LMP is greater than the retail rate. Therefore, the LMP minus retail rate method would always be positive and provide a variable payment to demand response with variability similar to the payment made under the LMP method. The two approaches are similar in that the value ascribed to the demand response resource increases as LMP increases. The difference is the magnitude of the payment. For any non zero retail rate, the LMP minus retail rate method provides a smaller payment than would a full LMP method.

The payment of LMP minus the retail rate is also consistent with the highest level of economic efficiency under the *presumption that demand reductions are comparable to generation of energy.* This is true because the demand response resource will make its economic decision based on the LMP. The decision is made on the basis of LMP when the compensation is LMP minus the retail rate because the net financial impact on the demand response resource of making the decision to reduce demand is positive LMP The net financial impact is LMP because the demand responder has avoided spending the retail rate and also re-

ceives an additional payment of LMP minus the retail rate for a total payment of LMP. Therefore, when consumption has a greater value than LMP, the demand responder will prefer to consume rather than reduce consumption and receive LMP. If consumption has a value less than LMP, the demand response resource will prefer to reduce consumption and receive the LMP.

This is not the case when the demand response resource is compensated at LMP. When compensated at LMP the demand response resource will reduce consumption when the value of that consumption is less than LMP plus the retail rate. Conversely, if the value of consumption is greater than the LMP plus the retail rate, then the demand response resource will continue to consume when compensation is equal to the LMP.

Another rationale can be used in promoting the LMP minus retail rate payment method. It is important to recognize that the logic promoting this rationale is not related to efficiency in the wholesale market, but it instead draws a comparison between generation resources and third party providers similar to those envisioned in the ARC policy of Order 719. Compensating ARCS at a level equal to LMP minus the retail rate can be constructed on the basis that the retail rate is the price at which the ARC must implicitly purchase the right to consume energy from the retail customer before it can sell that right to consume energy into the wholesale market. This logic attempts to draw comparability between the reductions in demand and generation of energy, by comparing the ARC's implicit purchase of the right to consume from the retail cus-

tomer to the cost of a generator's production of the energy or purchase of the energy from another generator which enables the sale in the market. Again, this example illuminates the fact that demand reductions and supply increases are not comparable.

Another rationale for the payment of LMP minus the retail rate is supported by the logic that this payment makes the load serving entity responsible for paying the demand response resource indifferent between consuming a unit of energy or economic demand response. This rationale utilizes the same basic economic principle used in the rationale above concerning the relative economic decisions of a demand responder, but the focus and implications are different. A load serving entity would make a net payment of the LMP minus the retail rate to generation resources per MWh of energy consumed because the load serving entity would pay the LMP to the RTO, and would collect the retail rate from its customers. This rationale assumes that the load serving entity is exposed to the LMP. This rationale also assumes that the load serving entity does not also own generation which would be adversely affected by the demand reduction. This idea will be revisited in the section on payment of LMP to demand response resources.

Another issue concerning LMP minus the retail rate compensation method is jurisdiction. The Commission is in a sense right, assuming again that demand reductions are comparable to generation, to insist that the RTOs should pay the LMP to demand responders because it is the marginal value of energy in the marketplace. However, as a practical matter, the load serving entity will not want to increase rates

to its customers to compensate demand response resources it does not own. Therefore, the retail rate must be credited to the load serving entity that paid LMP for the demand response in the wholesale market in order to make it indifferent to purchasing energy or demand reductions. This could be done after the payment of LMP in the wholesale market by collecting the retail rate portion from the demand response resource through a state commission process.

However, one should expect less contention over the value of the retail rate credit if that value is established before the wholesale transaction. This could be accomplished through a tariff provision which established the retail rate to be netted from the LMP for each demand response resource. The tariff provision would be best constructed if it provided an ex ante verification process through the state commission under whose jurisdiction the applicable demand response resources falls.

Each demand response resource would propose a retail rate that would be subtracted from the LMP to determine the LSE's obligation to the demand reponse resource. The proposed retail rate would be sent to the applicable state commission for approval before the demand response resource could participate in the market. This would allow the state to retain authority over its jurisdictional load serving entities while facilitating an efficient transaction with limited regulatory process. For the reasons in this section, the ICC supports the payment of LMP minus the retail rate for economic demand response in the wholesale market.

3. LMP Payment

The ICC notes that the Commission's NOPR proposes the payment of full LMP to economic demand response resources. The payment of LMP is appealing because LMP, by definition, is the marginal value in the wholesale market for electric energy. It would be true that the marginal value of the demand reduction is LMP if a demand reduction was comparable to increased generation, but it is not. The inconsistency arises from the simple fact that market rules simulate demand participation through supply offers.

Compensating demand reductions at LMP results in an increase in load serving entity expenses, without a commensurate increase in revenues. As shown in Section I.A., Figure 3 above, quantity sold is greater than quantity consumed when demand is reduced through a supply offer in the dispatch algorithm, *i.e.* $Q_1 > Q_2$. Therefore, the load serving entity is responsible for at least $(Q_1 - Q_2) \times P_3$ more dollars of cost than it would have been with the economically efficient solution under dynamic retail rates and zero compensation for demand reductions.

The payment of LMP relative to LMP minus the retail rate increases or creates perverse incentives for demand response resources and load serving entities. The following examples will compare the load serving entity's financial well being under the LMP payment for energy consumption, LMP payment for demand reduction and LMP minus retail rate payment for demand reduction. This analysis will be done under some simplifying assumptions. The assumptions are that the marginal cost of energy for a load serving entity is LMP and that the load serving entity does not

own the marginal generation which is displaced by the demand response resource.

- Under these assumptions the load serving entity expends LMP for the consumption of energy. When the energy is consumed the load serving entity receives the retail rate from its customer. Therefore, the load serving entity's net financial position is a loss of LMP minus the retail rate.
- When the load serving entity expends LMP on a demand reduction its net financial position is a loss of LMP Its net financial position is the loss of full LMP because the load serving entity will meter less energy consumption than it otherwise would have and therefore recoup zero dollars on the retail side from the customer for the non-consumption that it paid for in the wholesale market.
- When the load serving entity expends LMP minus the retail rate on a demand reduction its net financial position is the loss of LMP minus retail rate. The customer will not be metered for the demand reduction the load serving entity is paying for and subsequently does not pay the load serving entity for the MWh associated with the demand reduction.

Therefore, the payment of LMP minus the retail rate makes the load serving entity indifferent between the consumption of another unit of electricity and the consumption of a unit of demand response. Correctly aligning the load serving entity's incentives with the desired behavior is an integral part of accomplishing any policy objective.

It may be argued that the Commission is stepping into the states jurisdiction of the retail market. However, if tariffs are well designed, controversy over the jurisdictional issue can be avoided. Requiring an ex ante approval of the retail rate to be subtracted from the LMP at the time demand response resources are utilized in a fashion similar to that described in the previous section accomplishes this design. This type of approach preserves the state commission's jurisdiction in determining the retail rate to credit to the load serving entity to make it indifferent between energy consumption and demand reductions, while also circumventing the need for retroactive recovery of the retail rate portions of the demand response resources revenues. It could be imagined that the retroactive recovery of the retail rate portion from demand response resources could create inefficient process, costs, and risk of non-recovery.

C. Consequences of Subsidizing Demand Reductions

There is one consequence in particular that the ICC wishes to comment on. It has been explained here how any non-zero payment for demand reductions represents a subsidy that is not consistent with economic efficiency. If an individual or firm needs to be compensated to reduce consumption that would have otherwise taken place, then that compensation is a subsidy because economic reductions in demand occur based on relative prices of different market goods. None the less, there is value derived from allowing demand response resources to compete with generation resources, *e.g.* decreased market power and lower average wholesale prices, that would be realized natu-

rally if retail rates reflected marginal production costs. Attaining that value requires that some pecuniary incentive be offered to demand response resources offering demand reductions. However, demand response resources participating as suppliers in a RTO energy market may reduce the incentive for the implementation of retail rates which reflect wholesale prices. Furthermore, as the value of the subsidy increases, the state commission's likelihood of implementing time-differentiated retail rates decreases. It should be recognized that retail rates reflecting wholesale prices would be the most efficient means of allocating the scarce energy resources. The ICC recommends that the Commission recognize the implications of compensating demand response resources. Specifically, subsidizing demand reductions has the effect of decreasing the potential for retail rate reform.

Finally, there is another issue which results from the compensation of demand response at any level greater than zero. This issue arises when load serving entities are vertically integrated with generation regulated under state authority. Specifically, any non-zero payment to a demand response resource reduces the revenues to generators under the state regulatory authority. The result is a leakage of money to an entity outside of the state's regulatory authority. Therefore, retail rates to all customers may need to be increased in order to recover the costs of generators that would have otherwise been recovered through the purchase of electricity, but instead went to the payment of a demand response resource. Therefore, compensating demand response resources may increase the likelihood that state commissions will pro-

hibit the participation of demand response resources in the jurisdictions. While the Illinois is a retail choice state with no financial responsibility for generating assets, the ICC believes that these comments on this perceived concern facing those state commissions with responsibility for the solvency of load serving entities with generating assets will help to contribute to a full record before the Commission.

II. CONCLUSION

Limitations in metering technologies have prevented the active participation of consumers in the marketplace which has led to peak load conditions which can threaten reliability and/or increase overall costs. The ICC recognizes that there is value in demand response even when it is treated as an increase to supply when, in fact, it is a decrease in load. Treating demand response like a supply resource is a result of the control needed to balance the electric grid.

The combination of these and other factors have created the concerns which led to this proceeding. The ICC believes that the compensation issues only arise because of the inability for demand to react to market conditions due to the disconnect between retail and wholesale prices. However, given the value of demand response and the historical context of the industry, the ICC supports the payment of LMP minus the retail rate because it provides the right incentives to utilities on the margin to allow the participation of demand response on an economic basis.

WHEREFORE, for the reasons stated above, the ICC requests that the Commission consider these

comments and further requests any and all other appropriate relief.

Respectfully submitted,

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Dated: May 6, 2010

UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. RM10-17-000

Demand Response Compensation in Organized Wholesale Energy Markets

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May 12, 2010

COMMENTS OF THE ELECTRIC POWER SUPPLY ASSOCIATION

The Electric Power Supply Association ("EPSA")[1] hereby submits comments on the notice of proposed rulemaking issued by the Federal Energy Regulatory Commission ("FERC" or "the Commission") in the above-captioned proceeding on March 18, 2010.[2] In the NOPR, the Commission proposes to revise its

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[1] EPSA is the national trade association representing competitive power suppliers, including generators and marketers. These suppliers, who account for 40 percent of the installed generating capacity in the United States, provide reliable and competitively priced electricity from environmentally responsible facilities. EPSA seeks to bring the benefits of competition to all power customers. The comments contained in this filing represent the position of EPSA as an organization, but not necessarily the views of any particular member with respect to any issue.

[2] *Demand Response Compensation in Organized Wholesale Energy Markets*, Notice of Proposed Rulemaking, FERC Stats. & Regs. ¶ 32,656 (2010) (the "NOPR").

regulations to establish a generic compensation approach for demand response ("DR") acting as a resource in organized wholesale energy markets. Specifically, the NOPR proposes that Independent System Operators ("ISOs") and Regional Transmission Organizations ("RTOs") with tariff provisions permitting DR providers to act as resources in the day-ahead and real-time energy markets be required to pay these DR resources, in all hours, the market price for energy (i.e., the full Locational Marginal Price ("LMP")) for such reductions regardless of whether a given DR provider is already properly compensated by saving the full LMP when not consuming power from the grid.[3]

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[3] The proposed compensation would *not* apply to DR programs administered for reliability or emergency conditions and would *not* apply to capacity, ancillary or other ISO/RTO markets. Apparently, the NOPR would *not* apply to the Southwest Power Pool, Inc. ("SPP") because it currently has no DR program or LMP energy pricing. *See* NOPR at P 8 & n.29. Further, the proposed compensation would *not* apply in non-ISO/RTO regions. *See* NOPR at n.4 ("This provision applies only to demand response acting as a resource in organized wholesale energy markets."). Commissioner Moeller stated:

> My concern here goes to highlight the differences between regions with competitive wholesale markets and those that consist of largely bilateral market structures. By imposing a uniform compensation requirement, this proposed rulemaking could further exacerbate bifurcated approach toward national policy: entities in a competitive wholesale market must comply with increasingly burdensome requirements while entities operating in bilateral markets are often free from requirements that otherwise advance national policy goals.

NOPR at 33,988 n.12 (Moeller, Comm'r, dissenting & concurring).

Executive Summary

EPSA agrees that appropriate, economic and efficient participation by DR resources can provide efficiency benefits (both economic and operational) to wholesale electric markets, and appreciates the Commission's willingness to receive stakeholder input on the subject of compensation for DR.[4] EPSA and its members fully support participation by diverse resources in the ISO/RTO markets. Indeed, EPSA's members have been—and continue to be—active in stakeholder processes to facilitate such integration. EPSA has also supported and participated in numerous proceedings and efforts to develop viable, properly structured DR products.[5] Additionally, many EPSA member companies are developing and providing demand response products in many forms and across many regions.

As EPSA explained in the now-terminated Docket No. EL09-68 proceeding involving DR compensation in the PJM Interconnection, L.L.C. ("PJM"),[6] however,

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[4] Commission News Release, *FERC Seeks Comment on Demand Response Compensation in Organized Markets* (Mar. 18, 2010) (Chairman Wellinghoff noting that he is "eager to hear what stakeholders have to say about this").

[5] See footnote 22 below for examples.

[6] NOPR at P 23. See also: *Motion of the Electric Power Supply Association to Reject or, in the Alternative, for Extension of Time*, Docket No. EL09-68-000 (September 25, 2009); *Motion to Answer and Answer of the Electric Power Supply Association with White Paper by Professor William W. Hogan*, Docket No. EL09-68-000 (October 30, 2009); *Answer of the Electric Power Supply*

EPSA strongly opposes subsidizing DR through payment of full LMP in all hours in all cases. The NOPR fails to provide any support for imposing such a sweeping requirement in any one RTO, much less to enshrine such a requirement in the Commission's regulations as the one and only pricing element to be standardized across all ISOs and RTOs. Subsidizing one set of market participants in the manner contemplated by the NOPR would create substantial inequalities that would harm the market and consumers, and would produce rates that are demonstrably unjust and unreasonable.

EPSA appreciates that the NOPR carries forward the record from the Docket EL09-68 proceeding and incorporates by reference its pleadings in the PJM proceeding,[7] along with the policy paper EPSA filed in the PJM proceeding authored by noted Harvard University economist Professor William W. Ho-

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Association to Motion for Leave to Answer, Docket No. EL09-68-000 (November 30, 2009).

[7] *See* Motion for Leave to Intervene and Protest of the Electric Power Supply Association, Docket No. EL09-68-000 (filed Sept. 16, 2009); Motion of the Electric Power Supply Association to Reject or, in the Alternative, for Extension of Time, Docket No. EL09-68-000 (filed Sept. 25, 2009); Motion for Leave to Answer and Answer of the Electric Power Supply Association and White Paper by Professor William W. Hogan, Docket No. EL09-68-000 (filed Oct. 30, 2009) ("EPSA EL09-68 Answer"); Answer of the Electric Power Supply Association to Motion for Leave to Answer, Docket No. EL09-68-000 (filed Nov. 30, 2009).

gan.[8] EPSA elaborates here on why subsidizing DR by paying full LMP in all hours in all cases is inappropriate from a legal, economic and policy perspective, and provides, in Attachment 1 to these comments, an additional policy paper by Professor Hogan (the "Hogan Policy Paper") addressing the misunderstanding of the outcomes that should be expected if all DR resources were compensated in the manner proposed in the NOPR. Such outcomes would be inconsistent with economic efficiency and require certain customers to subsidize other customers through higher rates. The proposed rule may simply be unsustainable in the long run because there may not be enough consumers remaining who are willing to pay for the programs that the NOPR would mandate.

The NOPR as issued will not achieve its stated objectives[9] due to a number of significant legal, economic, policy and operational flaws with the DR compensation proposal, all of which render the proposal unjust and unreasonable. EPSA supports the Commission removing barriers to demand-side resource participation in all of the electricity markets. How-

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[8] *See* EPSA EL09-68 Answer, Attachment A, William W. Hogan, *Providing Incentives for Efficient Demand Response* ("Hogan EL09-68 Paper").

[9] NOPR at P 12, (" . . [W]e believe paying demand response resources the LMP in all hours will compensate those resources in a manner that reflects the marginal value of the resource to each RTO and ISO, comparable to treatment of generation resources. This will improve the competitiveness of the organized wholesale energy markets and, in turn, help to ensure that energy prices in those markets are just and reasonable.")

ever, requiring a generic price mechanism in order to subsidize one class of market participants at the expense of all others is inappropriate and counter to Commission policy and precedent to avoid subsidies when at all possible, and limit subsidies where necessary.[10] EPSA therefore respectfully requests that the Commission further consider the unanswered questions and serious concerns raised in this proceeding, as well as any and all workable solutions that may arise as the record in this proceeding develops, before moving forward with any standardized compensation guidelines or requirements, and consider whether any single approach is appropriate for all organized markets. In the meantime, the Commission should continue to consider DR compensation on a region-by-

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[10] See: *FERC Order No. 2003: Standardization of Generator Interconnection Agreements and Procedures*, FERC Stats. & Regs. ¶ 31,146 (2003), at P 695-698. (addressing concerns that providing transmission credits to an Interconnection Customer for the cost of network upgrades, unneeded but for interconnection of the new generating facility, provides the Interconnection Customer with an improper subsidy, particularly when the facility's output is sold off-system.) Occidental October 20, 2008 Comments at 20, *citing Golden Spread Elec. Coop. v. Southwestern Public Service Co.*, 123 FERC ¶ 61,047 (2008, at P 20-21. (Here the Commission required non-captive wholesale sales to be priced at incremental embedded cost rates so as to prevent captive customers from subsidizing such sales); *Entergy Servs. Inc.*, 58 FERC ¶ 61,234 (1992). *Certification of New Interstate Natural Gas Pipeline Facilities*, 88 FERC ¶ 61,227 (1999), *order on clarification*, 90 FERC ¶ 61,128, *order on clarification*, 92 FERC ¶ 61,094 (2000) (Certificate Policy Statement).

region basis through the Order No. 719[11] compliance process, and as additional proposals are developed through stakeholder processes in, and submitted by, individual ISOs and RTOs.[12]

As discussed in more detail in the comments below, the following are EPSA's specific concerns:

- The NOPR's primary premise is that more demand response is always better regardless of the amount of the subsidy cost paid by other consumers because doing so reduces wholesale power prices. On this pivotal point the NOPR utterly fails to provide any detailed substantive analysis supporting the NOPR's summary legal conclusions that (a) the current FERC-approved wholesale prices are no longer just and reasonable,[13] (b) the new pricing proposal is

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[11] *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶ 31,281 (2008) ("Order No. 719"), *on reh'g*, Order No. 719-A, Order No. 719-A, 128 FERC ¶ 61,059 (2009) ("Order No. 719-A").

[12] See compliance filings regarding various stages of economic demand response program design in Docket Nos. ER09-1048-000 (California ISO); ER09-1049-000 (Midewest ISO); ER09-1050 (Southwest Power Pool); ER09-1051-000 (ISO New England); ER09-1063-000 (PJM); and ER09-1142-000 (New York ISO).

[13] Note that the language of the NOPR is unclear as to whether it proposes to find only DR compensation now unjust and unreasonable, or whether the prices generally in the ISO/RTO markets are now deemed unjust and unreasonable. The latter seems to be the proposed finding. Either way the NOPR lacks the required extensive evidence to support such a finding. For reasons stated

just and reasonable, and, (c) the concept that a just and reasonable price means a "lower" price.

- Similarly, there is no showing or evidence in the NOPR that additional steps, such as paying full LMP in all hours in all cases, is necessary to ensure either the competitiveness of the markets or that wholesale rates continue to be just and reasonable. By contrast, the NOPR ignores market monitors' reports and other evidence that ISO/RTO wholesale electric markets, including energy markets, are and have been competitive and any market power is already sufficiently mitigated without the NOPR's proposal.
- The NOPR narrowly focuses on the ISO/RTO energy markets without any acknowledgement of the growth in and adequate compensation of DR resources participating in other ISO/RTO markets such as capacity, emergency, and ancillary service markets—all important components that work together to ensure adequate compensation for demand resources just as they are expected to do for supply. Additionally, the Commission should look at DR resource participation as a whole within each ISO/RTO to measure its growth in the organized markets. For instance, in terms of ensuring reliability and resource adequacy, which should be a pri-

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herein, the facts of which EPSA is aware would not support either such finding.

mary factor in the Commission's consideration and assessment of DR participation, the capacity market should be the primary market for this evaluation given the nature of DR products and their measurement.

- The NOPR would inappropriately—and inexplicably—standardize only one discrete pricing element across the ISO and RTO regions, while allowing for regional differences on all other market pricing elements even though it is the totality of these interrelated pricing elements that govern operational and investment decisions.
- The NOPR would require application of this standardized pricing element only in most organized markets—and does not address or require similar treatment in the non-RTO regions—which is an inconsistent approach and inappropriate reliance on the organized markets in order to achieve what the NOPR argues is a national policy goal intended to facilitate DR participation across the country.
- If implemented as proposed, the NOPR would lead to a perverse economic incentive for load to enter into agreements to take generation behind the meter when possible (as DR providers specifically advocated in the underlying PJM proceeding), thereby meeting load energy obligations outside of the RTO market while also being paid LMP by other consumers in the RTO for the load reduction on its system. The at-

tached Policy Paper by Professor William W Hogan addresses this and other market inefficiencies presented by the NOPR proposal, along with recommendations for development of efficient demand response policy alternatives, including appropriate compensation approaches, based on three general types of DR.

- The NOPR incorrectly attempts to resolve retail market barriers to DR participation (i.e., lack of dynamic pricing) through a wholesale pricing fix.

- The NOPR proposes enhanced compensation for vaguely defined "DR," while NAESB and NERC processes to establish standards defining DR products and accurately measure DR to ensure and maintain reliability are not yet complete. Consideration of any standardized pricing mechanism must await the successful implementation of measurability and verification tools that ensure that demand-side resources can and will perform when required; to institute the pricing mechanism first is to put the cart before the horse, and may not be appropriate after standards are approved based on whether and how demand-side resources are integrated into each ISO/RTO market; and

- The NOPR incorrectly assumes that one MW of demand always equals one MW of supply under all conditions. These DR resources simply are not "full" substitutes based on the nature of

their participation and the rules applicable to each resource in the energy markets.

I. COMMUNICATIONS

All pleadings, correspondence and other communications concerning these comments should be directed to:

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II. BACKGROUND

The Commission initiated this NOPR proceeding based on its "concern[] that *some* existing, inadequate compensation structures have hindered the development and use of demand response. (Emphasis added.)"[14] The NOPR does not, however, specify which existing compensation structures have given rise to this concern. Furthermore, the proposed solution is not targeted to those structures found to be inadequate. Instead, the NOPR indiscriminately proposes that "paying demand response resources the LMP in all hours will compensate those resources in a manner that reflects the marginal value of the resource to each RTO and ISO, comparable to treatment of generation resources."[15] While referring to various existing ISO/

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[14] NOPR at P 9.

[15] *Id.* at P 12.

RTO DR mechanisms with varying payment schemes (all of which, EPSA notes, the Commission found to be just and reasonable), the NOPR again provides no specifics, declaring that:

> As we have gained experience with these programs, we are concerned that the current compensation levels ***appear*** to have become unjust and unreasonable. Providers may submit price and quantity bids into the organized wholesale energy markets and the market clears at the marginal resource yet they fail to compensate demand response at levels that reflect the marginal value of the resource being used by the RTO or ISO to balance supply and demand. The current wholesale compensation levels ***may*** therefore be leading to under-investment in demand response resources, resulting in higher, and unjust and unreasonable, prices in the organized electricity markets. To help ensure that wholesale prices in ISOs and RTOs remain just and reasonable, we are proposing to require each ISO and RTO to pay the LMP to demand response providers participating in the organized wholesale energy markets.[16]

The Commission then poses a number of questions related to its proposal, including such critical questions as whether: current compensation is adequately procuring DR; there are alternative approaches to compensating DR resources; a reduction in consumption is comparable to an increase in electricity production

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[16] *Id.* at P 13. (Emphasis added.)

(i.e., does 1 MW of demand reduction always equal 1 MW of supply) and therefore whether DR resources and supply resources should receive comparable compensation; paying LMP to DR resources is comparable or is more or less than comparable to compensation paid to generation in the ISO/RTO energy markets; payment of LMP should apply to all hours, and if not, the criteria that should be used for establishing the hours when LMP should apply; whether requiring payment of LMP is appropriate across all ISOs/RTOs, or whether variations among ISOs/RTOs justify varying levels of DR resource compensation; and, whether the Commission should conduct periodic reviews of DR compensation, and if so, what criteria should be used for such assessments.[17] The Commission also seeks comments on proposed regulatory text and whether certain terms are sufficiently defined.[18]

Prior to issuance of the NOPR, there were three separate pending ISO/RTO proceedings involving the issue of proper DR compensation in PJM, the Midwest Independent Transmission System Operator, Inc. ("MISO") and ISO—New England Inc. ("ISO-NE").[19] However, the NOPR states that because the Commission is "addressing generically in this rulemaking proceeding the same issues raised in the *PJM* proceeding in Docket No. EL09-68-000, that docket is terminat-

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[17] *Id.* at P 19-21.

[18] *Id.* at P 22 & Proposed § 35.28(v).

[19] *Id.* at P 8 & n. 30.

ed."[20] It is unclear whether the MISO and ISO-NE proceedings are suspended pending the outcome of the instant NOPR proceeding; or whether and how this proceeding impacts the ongoing Order No. 719 compliance efforts which involve DR compensation issues.

Commissioner Moeller issued a statement concurring in part and dissenting in part to the NOPR, raising numerous concerns regarding the DR compensation proposal, including the lack of a thorough discussion of the evidence relied upon to substantiate Commission concerns and other supporting information on the proposal, the wide disagreement among stakeholders on the DR compensation issue in the PJM proceeding and the decision to terminate that proceeding, and the bifurcated approach toward national policy by precluding application of the NOPR proposal to the bilateral (non-RTO) markets, among other things.[21] EPSA shares many of the concerns raised by Commissioner Moeller and will address these issues herein.

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[20] *Id.* at P 23. ("The Commission will take administrative notice of the record in the *PJM* proceeding so that parties in that proceeding need not refile affidavits or other evidence introduced there.")

[21] NOPR, Commissioner Moeller Statement Concurring in Part and Dissenting in Part at 2, (Commissioner Moeller Statement).

III. COMMENTS ON PUTTING DEMAND RESPONSE IN PERSPECTIVE

A. EPSA Supports Appropriately Compensated Demand Response

EPSA is and has been a vigorous supporter of demand-side resources and energy efficiency as important elements of robust, competitive wholesale electricity markets,[22] and has participated in numerous

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[22] *See*: *EPSA PowerFact: NYISO Report by Noted Expert Shows Significant Progress Over Past Decade* (April 26, 2010). Available at: http://www.epsa.org/forms/uploadFiles/142D5000000A6.filename.EPSA_PowerFact_NYISO_Report_042610.pdf; *EPSA Comments on Draft Demand Response National Action Plan*, Docket No. AD09-10-000 (April 8, 2010); *Comments of the Electric Power Supply Association, re: NAESB Measurement and Verification Standards for DR*, Docket No. RM05-5-017 (October 22, 2009); *EPSA PowerFact: COMPETITIVE ISO/RTO REGIONS PROMOTE EFFICIENCY, AFFORDABIILTY, AND CLEAN ENERGY* (September 24, 2009). Available at: http://www.epsa.org/forms/uploadFiles/11B610000000A.filename.EPSA_PowerFact_-_9-24-09_Competitive_ISO-RTO_Regions_Promote_Efficiency_Affordability_and_Clean_Energy.pdf; *EPSA PowerFact: REGIONAL MARKETS BENEFIT CONSUMERS; LATEST APPA PAPER MISSES THE MARK AGAIN* (July 8, 2009). Available at: http://www.epsa.org/forms/uploadFiles/10C6C0000000D.filename.EPSA_PowerFact_-_7-8-09_Regional_Markets_Benefit_Consumers_-_Latest_APPA_Paper_Misses_the_Mark_Again.pdf; *EPSA Statement on Order No. 719 Issuance*: "Organized wholesale markets are delivering tremendous benefits, however they can be refined and improved where justified. Any changes to wholesale market rules must be viewed with an eye toward what measures are consistent with the significant investment needed to meet future electricity needs, while advancing demand response and improving the environment." (October 16, 2008) Available at:

proceedings to define and remove barriers to demand-side resources. Just as artificial market barriers must be removed for power supply sources, so should such market barriers be removed to allow entry for demand response. This is important to EPSA members as both supply providers and as demand response providers. The importance and benefits of demand response are not in question in this proceeding; concern over the proposal to set a generic price for economic demand response is limited to that critical pricing issue. Rather, as structured, the NOPR raises and then leaves unanswered numerous questions re-

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http://www.epsa.org/forms/documents/DocumentFormPublic/view?id=D9A3000002BC; *EPSA Statement on Costs of New Gen Investment*: "Today's sobering briefing was informative and should instruct critical decisions by federal and state policymakers. The country will need substantial investment in new power generation, along with demand response and efficiency measures, to reliably meet increased demand while achieving key environmental objectives." (June 19, 2008) Available at: http://www.epsa.org/forms/documents/DocumentFormPublic/view?id=C49E00000001; *Joint Compete/EPSA Press Release: FERC Commissioner Wellinghoff States Support for Competitive Electricity Markets to 'Enable Consumer Choices'* (November 5, 2007). Available at: http://www.epsa.org/forms/uploadFiles/a1ae00000022.filename.FERC_Commissioner_Wellinghoff_States_Support_for_Competitive_Electricity_Markets_to_%E2%80%98Enable_Consumer_Choi ces%E2%80%99.pdf; *EPSA PowerFact: Independent Reports Show Competitive Markets Delivering for Consumers and Leading the Way for Renewables and Demand Response.* (October 17, 2007) Available at: http://www.epsa.org/forms/uploadFiles/9fad0000002c.filename.Independent_Reports_Show_Competitive_Markets_Delivering_for_Consumers_and_Leading_the_Way_for_Renewables_and_De mand_Response.pdf.

garding the Commission's jurisdiction to standardize this discrete pricing mechanism, does not establish or identify a record to support the need for a standardized approach, and does not justify the reliance on payments of full LMP in all hours in all cases in order to achieve an unstated amount of desired demand response in only certain electricity markets.

B. The NOPR Does Not Account For DR's Role In All Markets

A central question raised by the NOPR is why the energy markets alone are targeted for consideration. In much the same way that supply, demand and efficiency are intrinsically tied together to constitute the electricity market overall, so are the different product markets which make up the overall wholesale electricity market intrinsically tied together to achieve the necessary revenues to support the supply and delivery of electricity. For suppliers, participation in the energy, capacity and ancillary services markets together yield payment for the commodity of power. Similarly, these markets, along with emergency programs, together compensate demand-side resources for their participation and contribution to the power market. In fact, demand-side resources are participating in an increasingly robust manner in many of these markets, particularly the capacity markets. Recent figures show that ISO New England has 1,330 MW of demand response capacity secured for 2010, NYISO had 2,383.6 MW of demand response provided in 2009, and PJM had committed capacity values totaling 7,089 MW for the 2009/2010 Delivery Year, which demonstrates the

significant commercial opportunities for DR in capacity markets.[23] In PJM, this represents extensive

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[23] ISO New England has stated that it has capacity resources totaling 32,670 MW available to supply electricity or reduce consumption, including 30,380 MW from generators, 1,330 MW from demand response, and 390 MW in electricity imports from neighboring regions. "The region's power grid is ready for the hot weather that typically drives up demand for electricity," said Vamsi Chadalavada, Chief Operating Office of ISO New England. "New England power plants have the capacity to generate electricity to meet peak demand We also have demand-side resources ready to manage electricity consumption if supplies get tight for any reason." "ISO New England's Summer Outlook: Sufficient Supplies Available Region's Power Grid Ready for the Season," April 26, 2010, available at: http://www.isone.com/nwsiss/pr/2010/summer10_04262010.pdf.

NYISO's Installed Capacity/Special Case Resources (ICAP/SCR) program has reported a total of 3,675 end-use locations registered as demand responders, representing 90% of the total reliability program enrollments in New York and 86% of the total reliability program registered MW. NYISO reports that the ICAP/SCR program, in conjunction with the Emergency Demand Response Program (EDRP) provided a total of 2,383.6 MW of demand response capability, which represents 7.7% of summer peak demand (30,844 MW). *NYISO Demand Response Programs Report*, Docket Nos. ER01-3001 & ER03-647 (January 15, 2010), pp. 1-4. Available here: http://www.nyiso.com/public/webdocs/documents/regulatory/filings/2010/01/ICAP_Report_1_15_10.pdf.

In PJM, the 2009/2010 Delivery Year marks the first time PJM has required Demand Side Resources to test their capability to deliver the reductions committed to meet capacity requirements. However, in aggregate, committed Demand Side Resources performed at 118% of their committed capacity values for the 2009/2010 delivery year. This meant the excess of committed capacity values totaled 1,299 MW for the 7,089 MW of Demand Side Resources

growth in the participation of demand in the capacity market; for the 2008/2009 Delivery Year there were 4,620 megawatts of demand response committed as capacity resources.[24]

These revenue avenues cannot be overlooked in an assessment of whether, how and to what extent DR is participating and being compensated in the marketplace, yet just such an assessment is missing from the NOPR as issued. Certainly, all of these revenue streams are considered if and when pricing elements such as scarcity pricing or capacity markets are being discussed for supply-side resources, none of which have been considered for standardization by the Commission in the past. In fact, both scarcity price formation and capacity markets are avenues to compen-

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required to test. *PJM Load Management Performance Report for 2009/2010* (December 2009), p. 4. Available here: http://www.pjm.com/markets-and-operations/demand-response/~/media/markets-ops/dsr/load-management-performance-report-2009-2010.ashx

[24] *2009 PJM State of the Market Report*, prepared by Monitoring Analytics (March 11, 2010), p. 16 of Section 2, Volume II, "Since the introduction of the capacity market on June 1, 2007 the capacity market has been the source of growth in total demand side revenues and demand side revenues from the capacity market were the only significant source of revenue in 2009. In 2009, payments from the Economic Program decreased from 2008 by $26 million or 96 percent, from $27.7 million to $1.2 million, while capacity revenue increased from 2008 by $161 million or 114 percent, from $141 million to $303 million since 2008. Synchronized Reserve credits decreased by $1.1 million, from $5.1 million to $4.0 million from 2008 to 2009. "For 2008/2009 Delivery Year figures, see http://www.pjm.org/markets-and-operations/demand-response/dr-capacity-market.aspx.

sate demand as well as supply. Scarcity pricing for shortages or operating emergencies are an important market element that would send signals to economic demand response, and are under development in the ISOs/RTOs currently pursuant to Order No. 719. The lack of robust scarcity pricing mechanisms in the ISOs/RTOs is in fact another barrier to the development and progress of demand-side resources. EPSA commends the Commission for its expeditious action to implement these market reforms, and notes that even in these instances generic or standardized pricing mechanisms are not appropriate.

C. The NOPR Fails To Account For Existing Market Conditions

Another concern raised by the NOPR is the assertion that lowering prices is a primary way in which DR can "improve the functioning and competitiveness of [the organized] markets "[25] Lower prices may be desirable in the short term, but the NOPR does not

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[25] NOPR at P 4. "Demand response acting as a resource in organized wholesale energy markets helps to improve the functioning and competitiveness of such markets in several ways. First, demand response can lower prices. When bid directly into the wholesale market, demand response—which results in lower demand—can result in lower clearing prices. For example, a study conducted by PJM, which simulated the effect of demand response on prices, demonstrated that a modest three percent load reduction in the 100 highest peak hours corresponds to a price decline of six to 12 percent. Demand response can also lower prices in the organized wholesale energy markets by reducing the need to dispatch higher-priced generation, or construct new generation, in an effort to satisfy load." (Citations excluded.)

explain or support this objective in the long term whether for demand response or supply. This is particularly troubling in the midst of the current and forward lower wholesale price environment for electricity across the country, which is not addressed in the NOPR. As reported by the Commission just last month in the presentation of the State of the Markets 2009 Report ("SOMs Report"), "With lower electricity demand and lower fuel costs, electricity prices fell by half. In the New York ISO and ISO-New England, the average electricity price in 2009 was the lowest since the markets began in their current form (NYISO in 1999, ISO-NE in 2003)." Intervening in the markets during what can be deemed to be a "bust" period in a cyclical capital intensive industry raises concerns as to the price levels expected by regulators and consumers with broader repercussions for both existing and new generation.[26]

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[26] "A Thought. 1Q10 Tweaks: Good Demand, Crummy Prices," Credit Suisse Research Analysts' Report, April 27, 2010. "In what can only be taken as a gratuitous understatement, commodity prices were awful in 1Q10 from the perspective of merchant power generators with natural gas and power prices falling (Exhibit 19) while coal prices held resiliently strong," Un-Empowering Forwards section, p 12. Analysis accompanied by chart forecasting continued decreasing forward prices for 2011-2013.

"Commodity Price Trends Raise Long-Term Questions For the U.S. Independent Power Producers Sector," Standard & Poor's Global Credit Portal Analysts Report, April 12, 2010. "Secondly, while building new baseload assets remains as difficult as ever, the recession has pushed reserve margin tightening out by several years and the strong emerging emphasis on energy efficiency and

As cited in the SOMs Report, the PJM independent market monitor has reported that prices in that region have fallen 10% even after adjusting for fuel.[27] While lower prices are desirable in the short term for electricity consumers (and according to the NOPR a primary concern of the Commission), such prices are not sustainable if below the cost to build, maintain or improve infrastructure that will be needed once the effects of the recession recede and pending environmental requirements are implemented. This situation has been documented for PJM over several years by its independent market monitor, who has consistently found that revenues in that market are too low to sustain the cost of new entry.[28] And with the in-

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demand-side management tends to further dampen heat rates," p. 6.

"U.S. Power Market Update: Economic Weakness Alleviates Reserve Margin Pressure, But Longer Term Constraints Remain," Citi Industry Report, (January 7, 2010), p. 4. "[T]he desire to invest in new projects on both the power gen and T&D side has diminished as a result of lower demand and reduced utility capex budgets. Additionally, our U.S. Electric Utilities team notes a recent acceleration in power plant cancellations and proposal withdrawals (some of which are not included in the NERC estimated pending level of power plant development)."

[27] *2009 PJM State of the Market Report*, prepared by Monitoring Analytics (March 11, 2010), p. 10. Note that before adjusting for fuel, the simple average LMP was 44.1 percent lower in 2009 than 2008 - $37.08 per MWh versus $66.40 per MWh.

[28] *2009 PJM State of the Market Report*, pp. *20* and 53:" In 2009, net revenues were not adequate to cover total fixed costs for a new entrant." and "If RPM is to provide appropriate incentives for new entry, the marginal price signal must reflect the actual cost of new

creasing costs of environmental compliance, existing generation resources are at risk of insufficient revenues as well.[29]

Additionally, as discussed in more detail below, it is unclear from the NOPR, and in light of each ISO/RTO market monitors' continual assessments year after year that the ISO/RTO markets *are* competitive,[30] as

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entry."; See also, PJM *2008 PJM State of the Market Report*, prepared by Monitoring Analytics (March 11, 2009), p. 37.

[29] See PJM 2009 State of the Market Report, p. 21: "There is a set of sub-critical coal units in 2008 and 2009 and a set of supercritical coal units in 2009 that did not recover avoidable costs even with capacity revenues. The total installed capacity associated with coal units that did not cover avoidable costs in 2009 was 11,250 MW."

[30] Even in years where prices rose, independent ISO/RTO market monitors found that the markets were competitive. See: *2008 State of the Market Report for the Midwest ISO*, prepared by Potomac Economics, p. ii. Available here: http://www.midwestmarket.org/publish/Document/7e7fdb_1225bf59491_-7e090a48324a/2008%20State%20of%20the%20Market%20-%20Final%20text.pdf?action=download&_property=Attachment.

PJM 2007 and 2008 State of the Market Reports, prepared by Monitoring Analytics, p. 1 and 2, respectively, Available here: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2008.shtml

ISO New England 2008 Annual Markets Report, p. 1. Available here: http://www.iso-ne.com/markets/mktmonmit/rpts/other/amr08_final_061709.pdf.

2008 State of the Market Report New York ISO, prepared by Potomac Economics, p. vii. Available here: http://www.nyiso.com/public/webdocs/documents/market_advisor_reports/NYISO_2008_SOM_Final_9-2-09.pdf.

to what has changed or is expected to change in these markets to justify the proposed standardization of an energy market premium to incent DR as necessary to maintain the competitiveness of these markets. The NOPR finds that,

> Based upon our review, the Commission is now concerned that evidence of demand reductions in PJM, and inadequate response participation, now and in the future, may be the result of compensation that is no longer just and reasonable, because, as detailed below, the existing and varying levels of compensation generally fail to reflect the marginal value of demand response resources to ISO and RTO energy markets.[31]

The NOPR, however, lacks any further explanation or evidence on this issue, nor is there any discussion of the "review" undertaken by FERC to determine that the existing and varying levels of compensation "generally fail to reflect the marginal value of DR resources" in ISO/RTO energy markets. Additionally, the NOPR goes on to state that due to this failure to compensate DR at levels that reflect its marginal value,

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California ISO 2007 Annual Report, p. 1. Available here: http://www.caiso.com/1f9c/1f9c8b49e9f0.pdf.

SPP 2008 State of the Market Report, prepared by Boston Pacific Company, p. 63. Available here: http://www.spp.org/publications/SPP%202008%20State%20of%20the%20Market%20Report.pdf.

[31] NOPR at P 10.

> The current wholesale compensation levels may therefore be leading to underinvestment in demand response resources, resulting in higher, and unjust and unreasonable, prices in the organized electricity markets.[32]

This tentative finding that wholesale prices *generally* in the ISO/RTO markets are unjust and unreasonable is neither explained nor supported by any evidence in the NOPR. In addition to the legal requirements not addressed for a just and reasonable finding, this apparent finding in the NOPR raises numerous additional unanswered questions. What levels of DR in each energy market would be deemed sufficient, and therefore imply that prices are just and reasonable? In its effort to achieve these increased levels, there has been no assessment whatsoever in the NOPR of how sweeping changes for increased DR participation in energy markets would impact ISO/RTO markets overall, impact regulatory stability, and affect investment in generation, including renewables and other emerging technologies. Even assuming that existing compensation mechanisms do not reflect the marginal value of demand response, the NOPR proposal fails to consider the metering energy, market accounting and cost responsibility of the energy that DR providers seek to sell in the energy market.[33]

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[32] NOPR at P 13.

[33] As an example, permitting a behind-the-meter generator to both reduce the retail energy bill of the customer and receive the full LMP as if that MW were sold to other wholesale loads would overcompensate the behind-the-meter generator. This would be

In both PJM and ISO-NE, the capacity markets currently are undergoing extensive review and reform as prices in those markets have been deemed to be insufficient to cover the cost of new entry. In tandem with historically low energy prices, it is a questionable time for additional reform—standardizing only one of many market pricing mechanisms—with the sole purpose of incenting greater amounts of demand response *in order to further* lower energy prices. If lower prices across all markets are an accurate reflection of the supply and demand fundamentals in the market today and going forward, then those price signals will reap what is efficient and appropriate in the market in terms of how much supply and demand (and of what types). There is serious concern, however, if low prices are artificially achieved on top of the extensive existing mitigation mechanisms due to the active price intervention of regulators by overcompensating broadly defined demand response. EPSA believes the NOPR as issued threatens to create a distorted price signal based on the desire to incent through subsidies one narrow element of the marketplace. In light of concerns over the extent of capital investments needed to support climate and other environmental policies, price signals must accurately reflect to the maximum extent possible the full range of market fundamentals.

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analogous to paying the generation used to support wholesale station power needs the full LMP despite its consumption behind the station meter.

D. The NOPR Does Not Address Or Consider Existing Alternative Compensation Mechanisms or Proceedings

In establishing this NOPR proceeding, the Commission acknowledges that different DR compensation alternatives have been proposed recently, including in the now-terminated PJM proceeding and in a MISO proceeding. These proposals were not addressed or analyzed in any detail in the NOPR and are important to consider in assessing the legal and policy implications of the Commission's proposal to pay full LMP in all hours in all organized markets regardless of their differences.

In two cases the NOPR states that ISOs/RTOs currently compensate DR in the energy market with full LMP, implying there is an adequate empirical track record to justify expanding this pricing mechanism to other ISOs/RTOs. While FERC orders approving these pricing mechanisms are referenced, there is no further discussion of the experience in those markets. This is troublesome as in California (one of the two cases briefly cited by the NOPR), there is a "participating load program" in which CAISO allows qualifying resources to provide day-ahead and real-time energy and non-spinning reserves. While the compensation is full LMP, this program has not yet even been implemented and is not targeted to begin until August 1, 2010.[34] Therefore, there is no rec-

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[34] *California ISO Stakeholder Conference Call Presentation: Participating Load Refinements* (April 23, 2010), slide 3. Available here: http://www.caiso.com/277f/277fe2e65cdb0.pdf.

ord of the efficacy of the full LMP compensation. In NYISO full LMP is paid in the Day Ahead Demand Response Program ("DADRP") (the only economic, non- emergency, non-capacity program in NY), which only represents an hourly average offer of 2.05 MW, with decreasing participation in the program. Actual scheduled MWhs of DR in the DADRP program decreased by 72% from 2008 to 2009.[35]

In three of the other pending ISO/RTO proceedings related to DR compensation, pricing mechanisms have been proposed that reflect in some way or another LMP *minus* the Demand Responder's avoided cost of consumption, an economic principle widely supported by economists and notably by certain state public utility commissions,[36] rather than the NOPR's full LMP in all hours. Additionally, this general pricing approach with an offset from LMP was sup-

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[35] *NYISO Demand Response Programs Report*, Docket Nos. ER01-3001 & ER03-647 (January 15, 2010), pp. 1-4. Available here: http://www.nyiso.com/public/webdocs/documents/regulatory/filings/2010/01/ICAP_Report_1_15_10.pdf.

[36] *See* generally the Comments of the Illinois Commerce Commission, Docket Nos. RM10-17-000 and EL09-68-000 (filed May 6, 2010). Also, Comments of the Indiana Utility Regulatory Commission supporting payment to DR resources of LMP minus the generation portion of retail rates (LMP-G) in the now-terminated PJM proceeding, Docket No. EL09-68-000 (filed September 16, 2009). And, see Footnotes 38 and 39 below regarding the Organization of MISO States' support for a DR compensation proposal of LMP minus the Retail Rate (LMP – RR) filed by MISO in a pending Order No. 719 proceeding, Docket No. 3409-1049-002 (October 2, 2009).

ported by several stakeholder groups in individual markets. In the instant NOPR, these proposals were summarily dismissed in order to instead offer a minority proposal—full LMP in all hours—as the proposed generic pricing mechanism for all organized wholesale markets. The basis for this leap to the minority pricing proposal is not explained in the NOPR.

For instance, the MISO proceeding involves an Order No. 719 and 719-A compliance filing addressing participation of Aggregators of Retail Customers (ARCs) in MISO's energy and ancillary services markets, as well as the appropriate energy market compensation, which is proposed to be LMP minus the Retail Rate (LMP – RR).[37] Significantly, the Organization of MISO States (OMS) representing state regulators in MISO supports this proposed compensation, noting among other things, "that the formula prevents the provision of a distorted price signal to ARCs and participating retail customers."[38] The OMS explains

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[37] *Midwest ISO*, Filing re Aggregators of Retail Customers (in compliance with Order No. 719 and partial compliance with Order No. 719), Docket No ER09-1049-002, (October 2, 2009).

[38] *See* Comments of the Organization of MISO States at 3, Docket No. ER09-1049-002, (November 5, 2009). The Comments are supported by the following OMS members: Indiana Utility Regulatory Commission, Iowa Utilities Board, Kentucky Public Service Commission, Michigan Public Service Commission, Minnesota Public Utilities Commission, Missouri Public Service Commission, Montana Public Service Commission, North Dakota Public Service Commission, Public Utilities Commission of Ohio, Pennsylvania Public Utility Commission, South Dakota Public Utilities Commission, and Wisconsin Public Service Commission. The Illinois

the unbundled approach to the pricing noting that "[t]his compensation formula is based on two paired components, the "buy" side of the arbitrage and the "sell" side. The buy side of the formula is represented by the Retail Rate. The sell side is represented by the LMP."[39] In further discussing its support, OMS notes:

> In other words, payment of the full LMP is not an efficient price signal to the retail customer and the ARC. Unless the retail rate is subtracted, an ARC would find it profitable to sell load reductions when the retail rate exactly follows the LMP or even when the retail rate exceeds the LMP. This absurd result underscores the conclusion that payment of the LMP alone would be a distorted price signal.[40]

Commerce Commission abstained from the vote on these comments. The Manitoba Public Utilities Board did not participate in this pleading. The Minnesota Office of Energy Security and the Indiana Office of Utility Consumer Counselor, as associate members of the OMS, also participated in these comments and generally support these comments (Comments, pp. 8-9.).

[39] OMS Comments, p. 3. Also, see Hogan Paper at 19-21, Docket No. EL09-68 (filed October 30, 2009). (Professor Hogan discusses the benefits of an "unbundled transaction" model for use by PJM at settlement, where "[t]he basic idea would be to unbundle the demand response transaction into an energy purchase and an energy sale.")

[40] *Id.*, p. 5.

With respect to the contested and now terminated PJM proceeding,[41] PJM proposed certain changes to its Economic Load Response Program (Economic Program), including reinstating a subsidy payment during certain hours. PJM also proposed modifying the currently effective FERC-approved base compensation of LMP minus the generation and transmission components of the retail rate, i.e., (LMP – (G + T)) to LMP - G. An ad hoc coalition of Demand Response Supporters ("DR Supporters") filed an alternate proposal calling for payment of full LMP in all hours and likened the role of DR in energy markets to providing a grid balancing service.

EPSA was an active participant in the PJM proceeding and argued, among other things, that neither PJM nor the DR Supporters had demonstrated that the current FERC-approved compensation (without a subsidy payment) is unjust and unreasonable or that their respective proposals were just and reasonable

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[41] Of note, the Commission found that continuing a subsidy payment for certain PJM demand response providers would be unjust and unreasonable in December 2007. That Order notes, "Even without the subsidy payments, the Economic Program provides customers within PJM the incentive to reduce load based on the wholesale rates they confront." Further, it notes, "We cannot find it unreasonable for the PJM stakeholders to conclude that customers interested in demand response have already had sufficient opportunity to recover start-up costs, so that a subsidy payment is no longer necessary to create an incentive to participate in the program.' *Order denying Complaint re PJM Industrial Customer Coalition v PJM Interconnection LLC*, 121 FERC ¶ 61,315, Docket No. EL08-12-000 (December 31, 2007), P 26 and P 27.

alternatives. In support, EPSA offered the expert analysis of Harvard University economist William Hogan on DR compensation, who argued that payment of LMP without an offset for some portion of the retail rate overcompensates individual DR resources and may result in more DR than is economically efficient. The NOPR provides no discussion, much less persuasive rebuttal, of Professor Hogan's detailed analysis, relegating any reference to it to a footnote in the NOPR. Nor does the NOPR address the extensive record developed in the PJM proceeding.[42]

With regard to the PJM proceeding, the Commission references the PJM Market Monitor's (PJM MMU) findings that following the decrease in DR compensation (i.e., when the subsidy payments ceased to be effective based on prior FERC Orders), settled demand reductions in the Economic Program declined.[43] EPSA again stresses that the MMU report

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[42] NOPR at fn.44 and P 23 (terminating the PJM docket).

[43] *Id.* at P 10 and n.35.

2009 PJM State of the Market Report, prepared by Monitoring Analytics (March 11, 2010), p. 114 of Section 2, Volume II. "Load reduction levels decreased by 425,500 MWh, from 477,212 in 2008 to 51,684 MWh in calendar year 2009, an 89 percent decrease. Total payments in the Economic Program fell $26.5 million, from $27.7 million in 2008 to $1.2 million in 2009, a 96 percent decrease. Payments per MWh were $24 in 2009 compared to $58 in 2008. The Economic Program's actual load reduction per peak-day, registered MW decreased to 20.8 MWh for calendar year 2009, a decrease of 90 percent from 2008. In the calendar year 2009, the maximum hourly load reduction attributable to the Economic Program was 142.3 MW on January 16." (Citations omitted.)

reflects that a number of factors may have contributed to this decline and based on the PJM MMU's findings submits that it is questionable whether removal of the subsidy can be tied to a decrease in DR participation in the energy market at all. The PJM MMU concluded that while removal of the incentives may have reduced participation, the exact role is not known because there were changes in other key factors which directly impact participation. The PJM MMU noted other possible factors contributed to the decrease, including FERC-approved revisions to Customer Baseline Load (CBL) calculations (to prevent gaming), implementation of a settlement review process, and a drop in PJM price levels.[44]

E. The NOPR Does Not Acknowledge Retail Barriers or Other Factors Impacting The Role of DR In Markets

Importantly, the PJM MMU report further states that "*[t]he evidence does not support the claim that the removal of the incentive program resulted in a reduction of activity in the Economic Program* (emphasis

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[44] In the recent FERC State of the Markets Report 2009 presentation, FERC staff noted "With the recession and mild weather dampening demand, it is difficult to isolate the effect of energy efficiency and demand response programs. These programs are beginning to have a presence in many RTOs. Some allow demand response resources to be bid into the capacity market. In PJM, ISO-New England and the New York ISO, the amount of demand resources cleared through the capacity markets grew to 12 GW." April 15, 2010 FERC Sunshine Meeting, page 6 of slide presentation available here: http://www.ferc.gov/market-oversight/st-mkt-ovr/som-rpt-2009.pdf

added)."[45] The PJM MMU Barriers to Entry Report also acknowledged that demand-side subsidies do not directly address the root problem—the lack of real time price information at the retail level.[46] This fundamental, underlying issue regarding the lack of retail-level dynamic pricing serves as one of the key barriers, if not *the primary barrier*, to entry for DR resources—and has been acknowledged as such by both market monitors and other market experts.[47] The reality is that retail customers do not have the necessary metering infrastructure in order to inform demand so that it can respond to prices in the same way as consumers respond to all other markets by avoiding the cost of buying a product if the real time price exceeds the good's perceived value. This retail infrastructure problem is not resolved by paying greater wholesale prices for load reductions than the customer would have saved had the necessary enabling infrastructure been in place.

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[45] See Monitoring Analytics, Barriers to Demand-side Response in PJM, (July 1, 2009), ("PJM MMU Barriers to Entry Report"), available at http://www.monitoringanalytics.com/reports/Reports/2009.shtml.

[46] *Id.*, pp. 2-3, 27.

[47] See: *Report on Demand Response of Potomac Economics, Independent Market Advisor for the New York ISO*, Docket Nos. RM07-19-000 and AD07-7-000 (May 15, 2009) pp. 4-5; *Barriers to the Demand Side Response in PJM*, prepared by Monitoring Analytics (July 1, 2009); *Fostering Economic Demand Response in the Midwest ISO*, prepared by the Brattle Group for the Midwest ISO. (December 30, 2008). Available here: http://www.brattle.com/_documents/uploadlibrary/upload729.pdf.

The NOPR itself supports the point that there is little nexus between a wholesale pricing fix to address what are mainly barriers to entry at the retail level, including a reference to a Commission Staff report detailing such barriers.[48] Commissioner Moeller also points to this disconnect stating the following:

> Ultimately, I want demand response to thrive and succeed in all the energy markets. However, there are only so many policy decisions and rulemakings that this Commission can make to encourage its development. As mentioned in the preamble [to the NOPR], *the primary barrier to increased demand response is the disconnect between retail and wholesale prices and the remedy resides at the retail level where there is a lack of dynamic pricing.* The approach embraced in the NOPR may also lead to a situation where residential ratepayers could be subsidizing other classes of service while unable to participate themselves in demand response programs. Absent attention to these issues, it will be difficult for any proposal to place generation and demand response on a precisely level playing field.[49]

As discussed in more detail later in these comments, the attached policy paper from Professor Hogan ad-

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[48] NOPR at n. 46, Federal Energy Regulatory Commission Staff, A National Assessment of Demand Response Potential (June 2009), available at http://www.ferc.gov/legal/staff-reports/06-09-demand-response.pdf.

[49] NOPR, Commissioner Moeller Statement at pp. 4-5. (Emphasis added.)

dresses in more detail a scenario similar to Commissioner Moeller's concern that the NOPR may lead to a situation where certain DR resources choose to take load "behind the fence" resulting in remaining market participants, including residential consumers, subsidizing costs. Professor Hogan describes the economically perverse incentive paying demand response full LMP in all hours would provide for generation to move behind the meter when possible, thereby meeting load energy obligations outside the RTO market while being paid LMP by the RTO for the load reduction on its system. Nothing in the NOPR's proposed tariff language addresses this flaw and in fact the proposed definition of "demand response" would allow it. In addition, the affidavits of the DR Supporters in the underlying PJM proceeding expressly advocate that demand shifting off the grid, not just actual demand reductions, will qualify for subsidy payments.

The more recent PJM MMU's 2009 State of the Market Report reiterates several points of interest raised in the July 2009 Barriers Report.[50] First, the PJM MMU recognized with specificity that between 2008 and 2009, "[t]here were many factors that contributed to the lower levels of participation and lower revenues in the Economic Program, including lower price levels in 2009, lower load levels, and improved

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[50] Monitoring Analytics, PJM State of the Market – 2009 (March 11, 2009) (PJM 2009 SOM Report), available here: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2009.shtml.

measurement and verification."[51] The PJM MMU also noted that while payments from the Economic Program have fallen substantially since 2007, capacity revenue for DR has increased significantly (rising 114% to $303 million from 2008 to 2009).[52] The PJM MMU also raised the following concerns:

> PJM and the MMU should continue efforts to ensure that market power is not exercised on the demand side of the market, particularly via gaming of the measurement and verification process. There are significant issues with the current approach to measuring demand-side response MW, which is the basis on which program participants are paid. Recent changes to the settlement review process represent clear improvements, but do not go far enough.[53]

The recent PJM MMU findings are compelling and raise several points for the Commission's consideration: First, the PJM MMU's 2009 SOM Report re-

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[51] PJM 2009 SOM Report, p. 17. Additionally, in joint comments filed on FERC's proposed RTO performance metrics, APPA and ELCON similarly noted that many factors influence the lower LMP prices in the RTO markets, "For example, if LMPs fall, as they did in 2009, this is not necessarily indicative of the performance of RTO markets and could simply be a reflection of declining fuel costs, reduced demand due to adverse economic conditions, and other factors." These factors clearly impacted the revenues and incentive to participate for DR as well as for supply. See: *Initial Comments of the APPA and ELCON*, Docket No. AD10-5-000 (March 5, 2010), p. 10.

[52] PJM 2009 SOM Report, Vol 2, p. 111.

[53] PJM 2009 SOM Report, Vol 1, p. 10.

flects that DR participation levels as a whole across the PJM markets are increasing. (This is also reflected in the significant level of DR participation in the ISO-NE capacity market.) For FERC to limit its focus in the NOPR to the energy market only—when there is broad and lucrative participation and a range of DR products offered within the various other ISO/RTO markets[54]—is inexplicable and does not reflect the full ability of DR to respond to price signals or to participate meaningfully in all electricity markets today.

F. The NOPR Does Not Address The Lack Of DR Metrics

The PJM Report also underscores that important underlying metrics to measure, verify and assess DR response are not yet sufficiently in place. EPSA submits that such metrics must first be established and in effect as a precursor to and condition precedent to a DR resource receiving compensation for participation in any ISO or RTO market (with any such payments reflecting the DR resources' avoided costs of consumption). For example, the Commission recently issued a final rule to incorporate by reference in its regulations the NAESB standards to categorize various DR products and services and to support measurement and verification of these products and services in the wholesale electric markets (NAESB Phase

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[54] Fostering Economic Demand Response in the Midwest ISO, prepared by the Brattle Group for the Midwest ISO. (December 30, 2008), p 49. Available here: http://www.brattle.com/_documents/uploadlibrary/upload729.pdf.

I M&V Standards).[55] The Phase I measures, while helpful, only serve as a framework and lack necessary detail and specificity, which is intended to be developed in the NAESB Phase II M&V Standards development process now underway.

The Commission's NAESB Phase I M&V Standards final rule notes that "[w]hile we do not expect NAESB to develop a single performance evaluation method, we reiterate that greater standardization of the performance evaluation methods will improve the accuracy of measuring and verifying DR performance and may reduce costs."[56] The Commission requests that NAESB seek to conclude its Phase II M&V Standards development within one year from the effective date of the order, or to file a report with the Commission at that time indicating the progress it has made, which the Commission can then build upon to propose standards or establish procedures for development of such standards. The Commission further notes the utility of these standards to related NIST and NERC initiatives.

EPSA commented on the Phase I M&V Standards raising concerns that they are not thorough enough (following a more than two-year NAESB process) and urged the Commission to set a deadline for the Phase II process, which will require more detail for the M&V

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[55] *Order No. 676-F: Standards for Business Practices and Communication Protocols for Public Utilities*, 131 FERC ¶ 61,022, Docket No, RM05-5-017 (April 15, 2010) ("NAESB Phase I M&V Standards").

[56] *Id.*, at P 34.

Standards to be truly viable. Currently, the rules needed to assure reliability of DR acting as a resource in energy markets are FERC-approved business practices, not tariff provisions, and allow DR reporting entities significant discretion until the Phase II M&V Standards are completed (expected in late 2011).

In a related effort, NERC is in the process of developing demand response measurement through its Demand Response Availability Data System ("DADS").[57] The NERC Rules of Procedure ("ROP") will require a change to make it mandatory for DR entities to respond to surveys about how much dispatchable and controllable demand response they provide. Moreover, NERC is in the process of defining demand response entities in its Functional Model. After completion of these changes NERC will be able to define DR and curtailment service entities for inclusion in the compliance registry. The timing for this effort, as well as the NAESB effort, will take a year or longer. As reflected in the NERC DADS Report, currently DR cannot be consistently quantified or counted on for reliability and the first mandatory data collection effort will not be concluded until August 2011.[58] The NERC DADS report seems to suggest that the data that will come into the DADS system pursuant to the NAESB Phase I M&V Standards will

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[57] NERC, Demand Response Availability Data System (DADS): Phase I & II Final Report, (March 5, 2010). ("NERC DADS Report")

[58] *Id.*, pp. 2-3, Table C: DRDTF and DADS Phase I & II Milestones for Implementation.

have a high probability of being inconsistent and will require robust analysis to provide reliable data for the 2011 reporting period.[59] EPSA submits it is not appropriate to consider establishing generic compensation for DR in energy markets when meaningful metrics are not in place for verifying and assessing that DR resources are actually available to ensure long-term reliability objectives. Additionally, once measurability standards are in place, it does not follow that it will be appropriate to consider generic pricing for demand response. Certainly verification will remove an important barrier to demand-side resources, allowing each ISO/RTO market to better integrate that resource into its system reliably and consider how to value that resource within the context of its market design and compensation streams.

IV. COMMENTS ON LEGAL AND ECONOMIC ASPECTS OF THE NOPR

A. Legal Arguments Not Addressed By The NOPR

a. The NOPR Does Not Establish that the Commission Has the Authority to Require "Just and Reasonable" Compensation for DR Resources

In the NOPR, the Commission speculates that inadequate participation by DR in organized markets "may be the result of compensation that is no longer just and reasonable."[60] Even if the Commission had evidence that this was the case—and it cites none in

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[59] *Id.*, pp. 13-18.

[60] NOPR at P 10.

the NOPR—the fact remains that it has not adequately attempted to set forth the basis for its claimed jurisdiction to mandate that DR providers in ISO and RTO energy markets receive "just and reasonable" compensation for providing non-jurisdictional DR services.

i. The Commission Is Not Empowered To Set Rates For Purposes of Providing "Just and Reasonable" Compensation to DR Providers

EPSA is not aware of any legal basis for the NOPR's assertion that DR service providers have a right to "just and reasonable" compensation under the Federal Power Act ("FPA"). The Commission's ratemaking authority under Sections 205 and 206 of the FPA applies only to rates charged by a "public utility" for the services subject to the jurisdiction of the Commission, namely, for wholesale *sales* or transmission of electric energy in interstate commerce.[61]

In Section 35.28(b)(5) of its regulations, the Commission has broadly defined DR as "a reduction in the consumption of electric energy by customers from their expected consumption in response to an increase in the price of electric energy or to incentive payments designed to induce lower consumption of electric energy."[62] Thus, DR is equivalent to a ***retail purchase*** that will not be or was not made. DR is *not* a FERC-jurisdictional ***wholesale sale*** by the terms of the Commission's own regulations. As the Commission explained in a unanimous order issued earlier this year:

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[61] 16 U.S.C. §§ 824d, 824e (2006).

[62] 18 C.F.R. § 35.28(b)(5) (2009).

> [W]here an entity is only engaged in the provision of demand response services, and makes no sales of electric energy for resale, that entity would not own or operate facilities that are subject to the Commission's jurisdiction and would not be a public utility that is required to have a rate on file with the Commission.[63]

For the same reasons, agreements to provide services from DR resources are not "paper facilities" subject to the Commission's jurisdiction because these agreements are "agreements ***not*** to purchase electric energy under certain circumstances, rather than agreements to sell electric energy at wholesale."[64]

As the Commission's ratemaking and refund jurisdiction under Sections 205 and 206 are expressly limited to rates charged by public utilities for jurisdictional services,[65] the Commission may not regulate, either directly or indirectly, the rates for *non*-public utility providers of DR services. The same result holds for non-jurisdictional DR services provided by an entity that is a public utility for other purposes (as was the case in *EnergyConnect*). It is well settled that, when a regulated entity provides both Commission-jurisdictional and non-jurisdictional services, the

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[63] *Order conditionally granting market-based rate authorization and providing guidance re EnergyConnect, Inc.*, 130 FERC ¶ 61,031, Docket No. ER09-1307-000/001 (January 19, 2010), at P 30. ("*EnergyConnect*")

[64] *Id.* (Emphasis added.)

[65] *See Bonneville Power Administration v. FERC*, 422 F.3d 908, 918 (2005). ("*BPA*")

Commission may exercise its ratemaking authority only with respect to the jurisdictional services. The bottom line is that whether compensation to DR providers is—or is not—too "high"[66] or too "low"[67] is outside of the Commission's jurisdiction.

ii. The Commission Cannot Regulate Jurisdictional Rates for the Sake of Increasing Non-Jurisdictional Rates

Even if the Commission ultimately were to conclude that inadequate DR participation in organized energy markets was causing Commission-jurisdictional rates to become unjust and unreasonable, its remedy may "operate only against the rate of

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[66] *See, e.g., Colorado Interstate Gas Co. v. FPC*, 324 U.S. 581 (1945). (*CIG*) In *CIG*, the Supreme Court acknowledged that, in fixing just and reasonable rates for interstate transportation service, it is necessary for the Commission to first allocate costs between the pipeline's jurisdictional and non-jurisdictional businesses, but emphasized that "[i]t is immaterial that the revenues from the intrastate sales or the direct industrial sales exceed their costs, since the authority to regulate those phases of the business is lacking." *Id.* at 588. The court affirmed the Commission's remedy—a rate reduction for the jurisdictional services only—as it was "based solely on the excess of revenues over costs (including return) derived from the regulated business." *Id.* at 594.

[67] *See, e.g., United Gas Pipe Line Co.*, Opinion No. 671, 50 F.P.C. 1348, 1387 (1973) (noting that nonjurisdictional rates were "below fully allocated costs," but holding that "the only partly compensatory nature of the non-jurisdictional rates is irrelevant here to a determination of the just and reasonable rate for the jurisdictional sales").

jurisdictional sales."[68] Consequently, the Commission may not directly regulate the non-jurisdictional rates that DR service providers receive.

The Commission is similarly foreclosed from indirectly regulating non- jurisdictional rates through the exercise of its authority over public utilities' jurisdictional rates.[69] The Commission's specific proposal in the NOPR—to direct public utilities, *i.e.*, each ISO and RTO, to comply with the proposed rule on DR compensation—would do precisely that.[70] Because, as

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[68] *FPC v. Conway Corp.*, 426 U.S. 271, 279 (1976). (*Conway*) In *Conway*, the Supreme Court held that the Commission has jurisdiction to remedy an alleged "price squeeze" by a vertically integrated utility (*i.e.*, a claim that the price differential between the utility's retail and wholesale rates is not justified by cost differences and is too small for the utility's wholesale customers to compete with utility in the retail market). The Supreme Court further held that, in determining whether the utility's wholesale rates are just and reasonable, the Commission may determine how to allocate costs between the utility's nonjurisdictional, retail sales and its jurisdictional, wholesale rates. This allocation "is in order to insure that the wholesale rate is paying its way, but no more," not to consider the justness and reasonableness of the retail rate. *Id.* at 280.

[69] *See, e.g., Richmond Power & Light v. FERC*, 574 F.2d 610, 620 (D.C. Cir. 1978) (rejecting petitioner's argument that the Federal Power Commission ("FPC") could indirectly impose a requirement on a public utility (involuntary wheeling) that the FPC could not impose directly, by conditioning its approval of the public utility's jurisdictional rates on the wheeling requirement, because "[w]hat the Commission is prohibited from doing directly it may not achieve by indirection.").

[70] EPSA notes that in *EnergyConnect*, the Commission explained that it "has broad authority to regulate demand response as a

explained above, DR is not a service subject to the Commission's ratemaking jurisdiction, the Commission's proposal represents an impermissible "attempt[] to do indirectly what it could not do directly. "[71]

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practice that affects rates in organized wholesale electric markets under section 205(a) and (c) and section 206(a) of the FPA.' *EnergyConnect* at P 32 (*citing* 16 U.S.C. §§ 824d(a), 824d(c), and 824e(a) (2006)). While EPSA takes no position on whether the Commission may regulate DR as a practice affecting jurisdictional rates generally, the Commission may not rely on these provisions to circumvent the express limitations on its ratemaking authority. In this regard, EPSA notes that the Commission's "affecting" jurisdiction under these provisions extends only to rules, regulations, practices, and/or contracts that affect "such rates," *i.e.*, rates charged by public utilities for FERC-jurisdictional sales. 16 U.S.C. §§ 824d(a), 824d(c), and 824e(a) (2006). Notably absent from this list are "rates"—jurisdictional or otherwise—that affect public utilities' jurisdictional rates. Moreover, if the Commission were permitted to use its "affecting" jurisdiction to reach non-jurisdictional rates, this would nullify the express limitation of the Commission's ratemaking authority.

[71] *Altamont Gas Transmission Co. v. FERC*, 92 F.3d 1239, 1248 (D.C. Cir. 1996) (holding that a Commission order conditioning the grant of a certificate under Section 7(e) of the Natural Gas Act ("NGA"), 15 U.S.C. § 717f(e) (2006), on the requirement that an interstate pipeline change the rate structure of a non-jurisdictional affiliate was an impermissible attempt to circumvent the express limitations on the Commission's ratemaking authority under Sections 4 and 5 of the NGA, 15 U.S.C. §§ 717c, 717d (2006)). The Commission's proposal to regulate rates for non-jurisdictional services should also be distinguished from cases such as *Connecticut Department of Public Utility Control v. FERC*, 569 F.3d 477 (D.C. Cir. 2009) ("*CT DPUC*"), where the court found that the Commission had both direct ratemaking jurisdiction and, consequently, indirect "affecting" jurisdiction over inputs affecting the

iii. DR Rates Are Not "Components" of a Jurisdictional Rate Subject to Commission Review

In at least one instance involving cost-based rates for transmission service, the Commission has been permitted to review whether a non-jurisdictional "rate," which was to be used as a component to calculate a jurisdictional rate, was just and reasonable.[72]

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jurisdictional rate in question. In *CT DPUC*, the court held that the Commission has "affecting" jurisdiction over ISO-NE's Installed Capacity Requirement" (the "ICR"), which the court described as "a key input into the market-based mechanism" for determining ISO-NE capacity prices. *Id.* at 478-79. The court reasoned that, since the Commission "could directly set the price of capacity . . and [the ICR] . . necessarily affects prices but not new capacity construction," then Commission review of the ICR did not constitute "direct regulation of generation facilities in violation of Section 201." *Id.* 481-82 (*discussing* 16 U.S.C. § 824(b)(1) (2006)). *See also id.* at 482 ("[t]hat the Commission may do so directly [*i.e.*, regulate capacity prices] would seem to include the power to do so indirectly" through review of the ICR).

[72] *Transmission Agency of Northern California v. FERC*, 495 F.3d 663 (D.C. Cir. 2007) ("*TANC*"). In *TANC*, the court affirmed the Commission's decision to review the justness and reasonableness of the transmission revenue requirement ("TRR") of the City of Vernon, California ("Vernon"), a governmental entity excluded from the definition of public utility, because Vernon's TRR would be added to the TRR of other public utility transmission owners of the California Independent System Operator Corporation ("CAISO"), which would then be used to determine the rates for jurisdictional, cost-based transmission service. The court found that the Commission had "sufficiently demonstrated that it is impossible to ensure that CAISO's rates are just and reasonable without reviewing Vernon's TRR under the same standard." *Id.* at 672.

The *TANC* court permitted the Commission to do so, however, *solely* for the purpose of ensuring that the jurisdictional rate in question was just and reasonable, ***not*** to determine whether the non-jurisdictional seller was receiving adequate or excessive compensation. In fact, in TANC the Commission did find that the non-jurisdictional rate was excessive and ordered refunds, but the court held that the Commission ***cannot*** fix such non-jurisdictional rates at a just and reasonable level (*i.e.*, by requiring refunds), because it lacks the authority to order refunds by entities that are not public utilities.[73]

In contrast, there is no way in which DR rates can be viewed as a "component" of jurisdictional, market-based rates for energy in organized markets. DR corresponds to retail purchases of electric energy that

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[73] *Id.* at 674. *See also BPA*, 422 F.3d at 921 (noting that the Commission's "long-standing interpretation of §§ 205 and 206 confirm that governmental entities/non-public utilities lie outside its ratemaking and refund authority"). EPSA wishes to emphasize that, while the *BPA* and *TANC* courts discussed the exclusion of governmental entities from the definition of public utility in FPA Section 201(f), 16 U.S.C. § 824(f) (2006), this statutory exemption was not the sole or even principal basis for their holdings. Instead, the crucial issue for both the *BPA* and *TANC* was that the Commission's ratemaking and refund jurisdiction under Sections 205 and 206 is expressly limited to ***public utilities***, and these holdings apply equally to any entity that is not a public utility, whether because it is a governmental entity or otherwise. If anything, the argument against Commission jurisdiction is even stronger with respect to DR, because the non-public utility involved in BPA (an electric cooperative) was engaged in otherwise Commission-jurisdictional transactions, whereas DR providers are not.

have ***not*** been made. A non-purchase at retail simply cannot be a "component" of a wholesale sale. Moreover, to the extent the Commission reads *TANC* to grant it something like FPA Section 205 authority over non-jurisdictional rates, there are significant differences between cost-based transmission rates and market-based energy prices that militate against extending the *TANC* approach to cover DR compensation. The *TANC* court addressed a non-jurisdictional entity's TRR, a cost-based rate, that along with the TRRs of transmission-owning CAISO public utilities, would be added up to yield the total TRR for the CAISO region. Market-based rates for energy in organized markets are not set by adding up various rate components, but rather through the complex interplay of supply and demand in a continuous series of auctions, subject to security-constrained economic dispatch and resulting locational price differences. Consequently, there is no clear or linear relationship between DR compensation and the resulting market clearing prices, as there was between Vernon's TRR and the resulting CAISO transmission rates.

iv. The Energy Policy Act of 2005 Did Not Delegate to the Commission the Authority to Regulate DR Compensation

Immediately after asserting (without support) that it may regulate DR compensation pursuant to Section 205 of the FPA,[74] the NOPR goes on to imply that its proposal is also authorized by Section 1252(f) of the

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[74] NOPR at P 5 (*citing* 16 U.S.C. § 824d (2006)).

Energy Policy Act of 2005 (EPAct 2005).[75] The provision states that "[i]t is the policy of the United States" to encourage DR and to remove barriers to the participation of DR in energy markets.[76] Any reliance on this provision as expanding the Commission's ratemaking jurisdiction is misplaced. Section 1252(f) of EPAct 2005 is simply a statement of policy; it does not expand the Commission's jurisdiction to further that policy.[77] As the Court of Appeals for the District of Columbia Circuit (D.C. Circuit) recently observed in striking down the Federal Communications Commis-

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[75] *Ibid.* (citing Pub. L. No. 109-58, § 1252(f), 119 Stat. 594, 965 (2005)).

[76] EPAct 2005 § 1252(f).

[77] EPSA notes that subsequent legislation has provided further clarification, if any were needed, that the Commission has not been granted ratemaking jurisdiction with respect to DR. Specifically, the Energy Independence and Security Act of 2007 ("EISA"), Pub. L. No. 110-140, 121 Stat. 1492 (2007), includes a number of provisions addressing the Commission's authority and responsibilities with respect to DR, none of which delegate to the Commission the authority to adopt mandatory rules of any kind. The principal provision is EISA Section 529, which directs the Commission, working with public and private stakeholders, to prepare a report and make recommendations to Congress regarding measures that would facilitate the adoption and implementation of DR by the States and market participants. *See* EISA § 529 (*to be codified* at 42 U.S.C. § 8279). EISA also includes provisions directing the Commission to work together with other federal agencies to develop standards and protocols for "smart grid" technologies, including demand response. *See* EISA sec. 1305(d) (*to be codified at* 15 U.S.C. 17385(d)). These standards would not be mandatory or enforceable by the Commission. *See Smart Grid Policy*, 128 FERC ¶ 61,060 at P 23 (2009).

sion's (FCC) "net neutrality" rules, "Policy statements are just that—statements of policy. They are not delegations of authority."[78] The Commission cannot rely on a policy statement alone to justify an exercise of jurisdiction; it must show that its actions in furtherance of the policy are supported by "an express delegation of authority."[79]

To the extent that the Commission wishes to regulate DR compensation, it would need to rely on an express delegation of authority under the FPA. Reliance on Section 1252(f) of EPAct 2005 is particularly misplaced where the actions contemplated directly contravene express limitations on the Commission's authority, like those in Sections 205 and 206 of the FPA.[80]

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[78] *Comcast Corp. v. FCC*, 2010 WL 1286658 at *11 (D.C. Cir. Apr. 6, 2010) (striking down an FCC order, which regulated the internet network management practices of a cable television provider, that the FCC claimed was authorized under a similar provision of the Federal Communications Act, which stated that "[i]t is the policy of the United States to promote the continued development of the Internet and other interactive computer services," 47 U.S.C. § 230(b) (2006)).

[79] *Id.* at *10.

[80] *See, e.g., Richmond*, 574 F.2d at 620 (noting that the FPC had the "authority to impose conditions or requirements 'necessary or appropriate to promote the policies'" of the FPA, but that "such conditions may not contravene" the express requirements of the FPA) (internal citations omitted).

b. Focusing Solely On Lowering Prices Would Be an Abdication of the Commission's Responsibility to Ensure that Jurisdictional Rates Are Just and Reasonable as to Jurisdictional Public Utilities

The NOPR makes the surprising and unsupported assertion that inadequate DR compensation may be resulting in "unjust and unreasonable[] prices in organized electricity markets."[81] The NOPR goes on to suggest that increasing DR compensation and participation is necessary for the Commission to "fulfill its mandate to ensure that rates charged for energy are just and reasonable,"[82] because DR "can lower prices" and "mitigate generator market power."[83] The two predicates underlying the NOPR—that organized markets are insufficiently competitive and that market power has not been sufficiently mitigated—are factually incorrect. The organized markets have been shown to be competitive year after year by independent regional market monitors and the Commission itself.[84] Additionally, there is extensive market miti-

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[81] NOPR at P 13.

[82] *Id.* at P 5.

[83] *Id.* at P 4.

[84] *2008 State of the Market Report for the Midwest ISO*, prepared by Potomac Economics, p. ii. Available here: http://www.midwestmarket.org/publish/Document/7e7fdb_1225bf59491_-7e090a48324a/2008%20State%20of%20the%20Market%20-%20Final%20text.pdf?action=download&_property=Attachment.

PJM 2007 and 2008 State of the Market Reports, prepared by Monitoring Analytics, p. 1 and 2, respectively, Available here:

gation in all of the organized markets, none of which has been shown to be inadequate.

The NOPR, therefore, is operating on the assumption that more DR, more mitigation, and lower prices are always better, indeed required. By solely focusing on the potential for DR to lower prices, without regard to whether these rates will be compensatory, the NOPR if adopted as a final rule would represent an abdication of the Commission's obligations to ensure that rates for jurisdictional sales are just and reasonable as to jurisdictional public utilities, including EPSA members.

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http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2008.shtml

ISO New England 2008 Annual Markets Report, p. 1. Available here:http://www.iso-ne.com/markets/mktmonmit/rpts/other/amr08_final_061709.pdf.

2008 State of the Market Report New York ISO, prepared by Potomac Economics, p. vii. Available here: http://www.nyiso.com/public/webdocs/ documents/market_advisor_reports/NYISO_2008_SOM_Final_9-2-09.pdf.

California ISO 2007 Annual Report, p. 1. Available here: http://www.caiso.com/1f9c/1f9c8b49e9f0.pdf.

SPP 2008 State of the Market Report, prepared by Boston Pacific Company, p. 63. Available here: http://www.spp.org/publications/SPP%202008%20State%20of%20the%20Market%20Report.pdf.

i. Public Utilities Have Statutory and Constitutional Rights to Just and Reasonable Rates

Federally regulated entities' right to receive compensatory rates is grounded in the Fifth Amendment of the U.S. Constitution[85] prohibition against takings of private property for public use without just compensation.[86] In its landmark case *FPC v. Hope Natural Gas Co.*,[87] the Supreme Court held that the constitutional right to just compensation is coextensive with the FPA[88] requirement that such rates must, at a

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[85] U.S. Const. amend V, cl. 3.

[86] *See, e.g., Smyth v. Ames*, 169 U.S. 466, 546 (1898) ("*Smyth*"). In *Smyth*, the Supreme Court explained the basis for a regulated entity's constitutional entitlement to just compensation:

> [T]he Corporation performing such public services and the people financially interested in its business and affairs have rights that may not be invaded by legislative enactment in disregard of the fundamental guarantees for the protection of property. The corporation may not be required to use its property for the benefit of the public without receiving just compensation for the services rendered it by it.

Id. at 546. The same principle applies with respect to state regulation of public utilities:

> Rates which are not sufficient to yield a reasonable return on the value of property used at the time it is being used to render the service are unjust, unreasonable and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment.

Bluefield Waterworks & Imp. Co. v. Public Service Commission of W. Va., 262 U.S. 679, 690 (1923) ("*Bluefield*").

[87] 320 U.S. 591, 602 (1944) ("*Hope*").

[88] *Hope* was decided under provisions of the NGA that are "substantially identical" to Sections 205 and 206 of the FPA. *FPC v.*

minimum, provide a reasonable opportunity for the utility to recover of, and on, its investment.[89] In this regard, the setting of "just and reasonable" rates "involves a balancing of the investor and the consumer interests."[90] Such rates must provide "enough revenue not only for operating expenses but also for the capital costs of the business"[91] and be sufficient for the utility to "maintain its credit and attract capital."[92] The Commission's rate regulation is thus a two-way street: regulated sellers are prohibited from charging exploitative rates, and in return, they have a right to receive compensatory rates.

Sierra Pacific Power Co., 350 U.S. 348, 353 (1956). The pertinent sections of the statutes may be "cite[d] interchangeably." *Arkansas La. Gas Co. v. Hall*, 453 U.S. 571, 577 n.7 (1981).

[89] *Id.* at 607. The Supreme Court reached a similar conclusion regarding just compensation under the Fourteenth Amendment, U.S. Const. amend. XIV, § 1:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding, risks and uncertainties.

Bluefield, 262 U.S. at 692-693.

[90] *Hope* at 603. *See also Grand Council of the Crees v. FERC*, 198 F.3d 950, 965 (D.C. Cir. 2000) (explaining that "'the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated,' while there is a 'consumer interest in being charged nonexploitative rates.'") (internal citations omitted).

[91] *Hope* at 603.

[92] *Id.*

A single-minded focus on lowering jurisdictional rates, like that which appears to underlie the NOPR, is fundamentally at odds with the Commission's constitutional and statutory obligations to regulated entities, including the public utilities with market-based rate authority that EPSA represents. The conflict with the Commission's obligations is made all the more glaring by the NOPR's inordinate concern for whether unregulated DR service providers are receiving "just and reasonable" compensation for non-jurisdictional services without sufficient regard for whether the NOPR's "full LMP in all hours" will be just and reasonable to wholesale suppliers.

ii. Just and Reasonable Rates in ISOs/RTOs Must be Sufficient to Support Existing Facilities and Attract New Entry

In the ISO/RTO setting, the Commission has applied *Hope*'s directive that rates must be sufficient to cover capital costs and to attract capital to mean that just and reasonable rates must be sufficient to ensure an adequate supply of generation. This is because, in competitive markets, as under the traditional regulatory paradigm, sufficient rates serve both consumers' and investors' interests, as they are necessary to maintain reliability.[93] In fact, the Commission has applied

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[93] *See, e.g., San Diego Gas & Elec. Co.*, 93 FERC ¶ 61,121 at 61,358 (2000). There the Commission explained the convergence of consumers' and investors' interest in ensuring that rates are sufficient to ensure an adequate supply of generation. According to the Commission, prior to the development of competitive wholesale markets:

this principle from *Hope* as a cornerstone design element for organized markets by requiring ISOs and RTOs to adopt measures to limit or prevent subsidized, uneconomic entry because such entry can reduce prices to below a just and reasonable level. In unanimously accepting the buyer market power mitigation rule for the New York Independent System Operator, Inc. ("NYISO"),[94] the Commission explained that:

> Ratepayer interests generally centered on ensuring that rates were not excessive or unduly discriminatory. The need to ensure an adequate supply of generation usually was met through requirements imposed by states on franchise utilities to build or buy adequate power resources to meet demand consistently. Today, however, in states such as California, the adequacy of local power resources depends, not just on state requirements, but also on whether market prices are sufficient to elicit adequate supplies, through construction or otherwise. In other words, when supply is driven by market price instead of regulatory requirements, ratepayer interests may no longer depend solely on whether current prices are deemed too high, but also on whether prices are too low to elicit new supplies over time.

Id. at 61,358.

[94] *See, e.g., New York Indep. Sys. Op., Inc.*, 122 FERC ¶ 61,211 at P 100 ("*NYISO*"), *on reh'g and compliance*, 124 FERC ¶ 61,301 (2008). In *NYISO*, the Commission conditionally accepted NYISO's proposed rule, pursuant to which new entrants deemed "uneconomic" would be subject to an offer floor equal to 75 percent of the net cost of new entry for the first three years of operation. To prevent circumvention of the rule, new entrants deemed uneconomic would not be permitted to participate in bilateral transactions, or in strip or monthly auctions. *NYISO* at P 87.

> While a strategy of investing in uneconomic entry and offering it into the capacity market at a low or zero price may seem to be good for customers in the short-run, it can inhibit new entry, and thereby raise price and harm reliability, in the long-run. Under the FPA, the Commission must ensure that rates are just and reasonable. The courts have long held that establishing just and reasonable rates involves a balancing of consumer and investor interests.[95]

The Commission has approved similar buyer-side mitigation rules, for the same reasons, in PJM, NYISO and ISO-NE.[96] But despite these rules, ISO/RTO rates, particularly with respect to capacity markets, have already fallen well below the minimum level necessary for suppliers to cover their fixed costs and to attract new capital.[97] The Commission's proposal threatens to reduce ISO/RTO rates still further below compensatory levels.

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[95] *NYISO* at P 103 (citing *Hope*).

[96] *See PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331 at PP 103-104 (2006), *on reh'g and clarification and compliance*, 119 FERC ¶ 61,318 at P 165 (2007); *Devon Power LLC*, 115 FERC ¶ 61,340 at PP 113 and 115 (2006), *reh'g denied*, 117 FERC ¶ 61,133 (2006).

[97] *See* footnote 26 above.

iii. The Commission Has Provided No Evidence that Existing ISO/RTO Mitigation Has Become Unjust and Unreasonable

The NOPR provides no support for the startling conclusion that rates in ISO/RTO markets may have become "unjust and unreasonable," and that the proposed subsidies to DR are needed "[t]o ensure that wholesale prices in ISOs and RTOs remain just and reasonable."[98] The Commission has provided absolutely no evidence for this sweeping statement, in the NOPR or elsewhere, much less the substantial evidence necessary to survive judicial review.[99] It is also disturbing that the Commission would so casually cast doubt on the justness and reasonableness of existing ISO/RTO market rules, especially given its own repeated and consistent statements to the contrary. In Order No. 697-A, for example, the Commission adopted, on a generic basis, a "rebuttable presumption that the existing [ISO/RTO] mitigation is sufficient to address any market power concerns."[100] Moreover, the

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[98] NOPR at P 13.

[99] *See* 5 U.S.C. § 706(2)(E) (2006). *See also, e.g., Illinois Commerce Comm'n v. FERC*, 576 F.3d 470, 477 (7th Cir. 2009) (explaining that a reviewing court "cannot uphold a regulatory decision that is not supported by substantial evidence on the record as a whole.").

[100] *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, FERC Stats. & Regs. ¶ 31,252, *clarified*, 121 FERC ¶ 61,260 (2007), *order on reh'g*, Order No. 697-A, FERC Stats. & Regs. ¶ 31,268 at P 111, *clarified*, 124 FERC ¶ 61,055, *order on reh'g*, Order No. 697-B, FERC Stats. & Regs. ¶ 31,285 (2008), *order on reh'g*,

Commission has repeatedly found that the existing mitigation in the various ISOs/RTOs is just and reasonable and that organized markets are sufficiently competitive to mitigate generation market power.[101]

The Commission has given no indication that there is some new or previously unknown system flaw in organized markets' mitigation measures that would cause them to have become unjust and unreasonable, much less that if they were, it is a result of inadequate DR compensation. Moreover, to the extent that the Commission may conclude that existing ISO/RTO mitigation has become uniformly unjust and unreasonable, the Commission's decision could not survive judicial review as it is an unexplained and unjustified departure from the vast body of Commission precedent find-

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Order No. 697-C, FERC Stats. & Regs. ¶ 31,291 (2009), *order on reh'g*, Order No. 697-D, 130 FERC ¶ 61,206 (2010).

[101] *See, e.g., PJM Interconnection, L.L.C.*, 123 FERC ¶ 61,169, *order on reh'g*, 125 FERC ¶ 61,340 (2008) (order rejecting complaints regarding PJM's market power screen, the three-pivotal-supplier test, but finding that mitigated prices were inadequate); *Connecticut ex rel. Blumenthal, et al. v. ISO New England Inc.*, 117 FERC ¶ 61,308 (2006), *reh'g denied*, 118 FERC ¶ 61,205 (2007) (order denying complaint alleging, among other things, that ISO-NE's mitigation of units subject to the Peaking Unit Safe Harbor bidding rules was inadequate); *California Elec. Oversight. Bd. v. California Indep. Sys. Op. Corp.*, 109 FERC ¶ 61,182 (2004) (order denying complaint seeking to require CAISO to adopt automatic mitigation procedures); *NSTAR Elec. & Gas Corp. v. Sithe Edgar, LLC, et al.*, 101 FERC 61,064 (2002) (order denying complaint that ISO-NE mitigation measures were inadequate to prevent units in an ISO-NE subregion from exercising market power).

ing that existing ISO/RTO mitigation is just and reasonable.[102]

iv. The Commission's Proposal Ignores the Danger that Over-Mitigation, Like Under-Mitigation, May Render Rates Unjust and Unreasonable

The Commission's proposal to increase DR compensation as proposed in the NOPR as a means of further mitigating generators' alleged market power[103] —in organized markets with existing market power and mitigation schemes that have been found to be just and reasonable—would likely result in over-mitigation, which, as the Commission has long recognized, can be just as harmful to competition as under-mitigation and may reduce regulated sellers' rates to unjust and unreasonable levels. The Commission and the courts alike have recognized the danger of over-mitigation. For example, in *Wisconsin Public Power, Inc. v. FERC*,[104] the court affirmed the Commission's

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[102] *See, e.g., Williams Gas Processing Gulf Coast Co. v. FERC*, 475 F.3d 319, 322 (D.C. Cir. 2006) (vacating Commission orders because the Commission "neither explained its action as consistent with precedent nor justified it as a reasoned and permissible shift in policy."); *Missouri Pub. Serv. Comm'n v. FERC*, No. 09-1121, slip op. at 12-13 (D.C. Cir. Apr. 13, 2010) (vacating Commission order in which it refused to address pipeline's acquisition premium where it was required to do so under applicable Commission precedent and failed to provide an adequate explanation for why it had not done so).

[103] NOPR at P 4.

[104] 493 F.3d 239 (D.C. Cir. 2007).

decision not to require the Midwest Independent Transmission System Operator, Inc. to include a market concentration analysis as part of its mitigation provisions, finding that the Commission's decision to do so:

> required striking a balance between, on the one hand, detecting and dampening exercises of market power and, on the other hand, allowing generators to charge prices that are high enough for them to recover their fixed costs.[105]

According to the Commission, this balance had to "reflect an appropriate trade-off between the interests of buyers and sellers—and, of course, setting a just and reasonable rate necessarily 'involves a balancing of the investor and the consumer interests.'"[106] The NOPR completely ignores jurisdictional sellers' interests, and by seeking to heap additional mitigation on top of the more than adequate and extensive existing ISO/RTO mitigation, the NOPR threatens to depress wholesale market-based rates below levels that are necessary for jurisdictional sellers to recover their fixed costs.

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[105] *Id.* at 262-263 (D.C. Cir. 2007) (affirming the Commission's decision not to require a market concentration analysis as part of the Midwest ISO's mitigation provisions due to its concerns that it would result over-mitigation).

[106] *Id.* at 262 (citing *Hope* at 603).

c. By Failing To Identify The Record Evidence Supporting Its Proposal, The Commission Has Failed To Provide A Meaningful Opportunity For Notice And Comment

The Administrative Procedures Act ("APA") requires the Commission to provide interested persons notice and a meaningful opportunity to comment on a proposed rulemaking.[107] In keeping with this obligation, the Commission must identify the reasoning and record evidence upon which it has relied in reaching its decision, so that interested parties have an opportunity to rebut the evidence proffered by the Commission.[108] In order to provide a meaningful opportunity for comment, such evidence "must be made available ***during the rulemaking***."[109] If the Commission "fails to provide an accurate picture of the reasoning that has led the agency to the proposed rule, interested

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[107] 5 U.S.C. § 553 (2006).

[108] *See, e.g., WJG Tel. Co., Inc. v. FCC*, 675 F.2d 386, 389 (D.C. Cir. 1982) (explaining that "[n]otice is sufficient 'if it affords interested parties a reasonable opportunity to participate in the rulemaking process,' and if the parties have not been 'deprived of the opportunity to present relevant information by lack of notice that the issue was there.'") (citations omitted); *Chamber of Commerce v. SEC*, 443 F.3d 890, 899 (D.C.Cir.2006) (explaining that "[a]mong the information that must be revealed for public evaluation are the 'technical studies and data' upon which the agency relies [in its rulemaking].") (citations omitted).

[109] *American Radio Relay League, Inc. v. FCC*, 524 F.3d 227, 237 (D.C. Cir. 2008) (emphasis added).

parties will not be able to comment meaningfully upon the agency's proposals."[110]

The NOPR is manifestly inadequate in this regard. As Commissioner Moeller noted, "the NOPR lacks a thorough discussion of the evidence that [the majority] relied upon to substantiate their concerns."[111] In fact, the Commission has not pointed to any evidence whatsoever demonstrating that current DR compensation levels have rendered Commission-jurisdictional rates unjust and unreasonable or that increasing DR compensation as proposed by the Commission is necessary for such rates to become just and reasonable.[112]

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[110] *Connecticut Light and Power Co. v. NRC*, 673 F.2d 525, 530 (D.C. Cir. 1982), *cert. denied* 459 U.S. 835 (1982) (*CL&P*).

[111] Commissioner Moeller Statement at 2.

[112] Instead, the only "evidence" that the Commission has chosen to cite is a part of the PJM MMU Barriers to Entry Report noting that the elimination of DR subsidies has coincided with a decrease in DR participation in a single RTO region. *See* NOPR at P 10 n.35. The Commission fails to mention, however, that the PJM MMU report goes on to state that "the exact role of the elimination of the incentive program is not known" due to changes in other key factors impacting DR participation, and ultimately concludes that: "The evidence does not support the claim that the removal of the incentive program resulted in a reduction of activity in the Economic Program." PJM MMU Barriers to Entry Report at 22. Of course, "there is no APA precedent allowing an agency to cherry-pick a study on which it has chosen to rely in part." *Solite Corp. v. EPA*, 952 F.2d 473, 500 (D.C. Cir. 1991) (quoting *Weyerhaeuser Co. v. Costle*, 590 F.2d 1011, 1031 (D.C. Cir. 1978)).

The Commission has similarly failed to "explain the need for a uniform compensation approach."[113]

This inadequacy is all the more unsettling in light of the Commission's incorporation of the record from the Docket No. EL09-68-000 proceeding, because, as Commissioner Moeller correctly notes, "the record in Docket No. EL09-68-000 shows wide disagreement in the industry regarding the issue of demand response compensation."[114] Even with this vast evidentiary record addressing a broad range of viewpoints already before it, the Commission makes no effort to identify the evidence that supports its proposal or to refute the considerable evidence that does not.

There are only two inferences that one can draw from the NOPR's failure to identify the factual or economic bases for its proposal: (1) none of the evidence submitted in Docket No. EL09-68-000 supports the Commission's proposal, or (2) some of that evidence supports the proposal, but the Commission has chosen not to identify that evidence until it issues its final rule. If the former is the case, then the Commission has manifestly failed to fulfill its statutory duty to support its decision with substantial evidence[115] and to engage in reasoned decision-making.[116] It also

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[113] Commissioner Moeller Statement at 4.

[114] *Id.* at 3.

[115] *See* 5 U.S.C. § 706(2)(E) (2006).

[116] If the Commission were to adopt its proposal, despite the absence of any evidence linking DR compensation to the level of DR participation, or to the justness and reasonableness of jurisdictional rates, the Commission would have failed to satisfy the most basic

begs the question of how, if the voluminous submissions of those advocating subsidies for DR in Docket No. EL09-68-000 provide no evidentiary support for the proposal, the Commission could ever adduce evidence sufficient to support a final rule adopting that proposal. If, on the other hand, the Commission has additional information not disclosed in the NOPR upon which it has relied, it would be helpful to do so or otherwise it will have denied interested parties "a fair opportunity to comment" and "to point out where that information is erroneous or where the agency may be drawing improper conclusions from it."[117]

B. Important Economic Considerations To Address

In addition to the numerous legal infirmities and unanswered questions with the NOPR proposal outlined above, EPSA submits the sweeping nature of the

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requirement of reasoned decisionmaking, namely, that its order must articulate "a rational connection between the facts found and the choices made." *Mo. Pub. Serv. Comm'n v. FERC*, 234 F.3d 36, 41 (D.C. Cir. 2000) (*quoting Columbia Gas Transmission Corp. v. FERC*, 628 F.2d 578, 593 (D.C. Cir. 1979)).

[117] *National Ass'n of Regulatory Utility Com'rs v. FCC*, 737 F.2d 1095, 1121 (D.C. Cir. 1984). The *CL&P* court explained the impropriety of such agency conduct as follows:

> To allow an agency to play hunt the peanut with technical information, hiding or disguising the information that it employs, is to condone a practice in which the agency treats what should be a genuine interchange as mere bureaucratic sport. An agency commits serious procedural error when it fails to reveal portions of the technical basis for a proposed rule in time to allow for meaningful commentary.

CP&L, 673 F.2d at 530-531.

NOPR proposal is simply unnecessary when viewed from a purely economic standpoint to incent the desired (albeit unspecified) increased levels of DR participation. Based on past experience with other types of incentive programs (such as "Cash for Clunkers"),[118] simply indiscriminately paying more to get more without limitations and qualifications is not an efficient economic approach. Unfortunately, the NOPR's compensation proposal as structured is likely to have serious unintended consequences for smaller consumers (and in fact, the opposite result from that which the NOPR envisions). The NOPR hones in on only one pricing element in one type of wholesale market, but instead should consider all relevant markets in which DR currently participates across the ISOs/RTOs (capacity, ancillary services and energy) to evaluate how market value and price is developed for DR resources and from there, to determine any steps that may be necessary to facilitate *efficient* levels of DR participation. For example, as discussed above, the capacity revenue for DR resources in PJM alone has increased 114% to $303 million from 2008 to 2009. This considerable value achieved from participation in the capacity market should not be ignored and must be consid-

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[118] A GAO recently concluded that though "the [American Cash for Clunkers Program] produced economic and environmental benefits, achieving its broad objectives the extent of the program's effects is uncertain." *US Government Accountability Office Report: AUTO INDUSTRY—Lessons Learned from Cash for Clunkers Program* (April 29, 2010), p. 29. Available here: http://energycommerce.house.gov/Press_111/20100429/GAO.Report.Cash.for.Clunkers.04.29.2010.pdf.

ered as part of a broader assessment of DR participation in the context of all relevant markets.

Importantly, the attached additional policy paper by Harvard economist Professor William W. Hogan ("Hogan Policy Paper") highlights the NOPR's misunderstanding of the outcomes that should be expected if all demand response resources were able to participate as proposed regardless of relevant circumstances. Such outcomes would be inconsistent with economic efficiency, require certain classes of customers to subsidize other customers through higher rates, and could render the demand response programs mandated by the NOPR unsustainable in the long run. As discussed by Professor Hogan,

> " adoption and implementation of the proposed rule could produce outcomes that are inconsistent with economic efficiency. **Certain consumers would be paid subsidies for reducing their consumption that exceed the payments that are necessary to induce them to consume electricity in an efficient manner. The cost of these subsidies would, in all likelihood, be shouldered by other customers, who would thereby be charged amounts that are unrelated to the cost of electricity they consume or any other service that is rendered to them.**[119] (Emphasis added)

Further, as previously articulated by EPSA in the PJM proceeding, payment of full LMP in all hours ignores the fact that demand response providers are ap-

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[119] Attachment 1, Hogan Policy Paper at 2.

propriately compensated by means of the cost they avoid by curtailing their consumption.[120] This is what occurs when power suppliers do not purchase the goods sold by those large industrial users (e.g., steel, cement and forest/paper products companies) who seek the NOPR's subsidy payments; power generators do not get paid by these large industrial entities for what power suppliers did not consume below expected levels from them.

As the PJM MMU stated in the PJM proceeding: "When a customer who pays LMP decides to consume one less MWh, its benefit is the price of that MWh that it avoided paying, the LMP in this case."[121] (It should be noted that PJM's current Economic Program in general replicates that result for retail customers who do not pay the actual wholesale market price for electricity under retail rate schedules, but instead pay a fixed price for electric service.) EPSA asserts, and the attached Hogan Policy Paper supports,[122] that LMP minus avoided costs for generation or the retail rate ensures that demand response is economically efficient and therefore does not skew competitive

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[120] PJM Interconnection, LLC, *Motion for Leave to Answer and Answer of the Electric Power Supply Association* And White Paper By Professor William W. Hogan at 6, Docket No. EL09-68-000, (filed October 30, 2009) ("EPSA Answer").

[121] PJM Interconnection, LLC, Motion for Leave to Answer and Answer of the Independent Market Monitor for PJM at 5, Docket No. EL09-68-000, (filed October 16, 2009) (PJM MMU Answer).

[122] The Hogan EL09-68 Paper filed with the EPSA Answer in the PJM proceeding also supports this position.

wholesale markets. In simple terms, if a generator's fuel cost exceeds the LMP, then that unit is not an economic resource at that time and will not be dispatched. Similarly, if LMP minus the applicable retail rate is insufficient compensation to a customer to offer demand response, then that demand resource is not economic as compared to other resources. In discussing the economic inefficiencies and other implications of the NOPR proposal, Professor Hogan explains,

> Paying the LMP to all consumers all of the time for imputed demand reduction will generally yield an inefficiently large amount of demand reduction paid for by those consumers who remain. This can be seen most easily in the case of consumers who pay the LMP for the electricity they consume. If such a consumer does not consume electricity, under the proposed rule, not only would it not have to pay the LMP, but it would also be paid the LMP for electricity it does not consume. So, if we assume that the LMP is $40/MWh, the imputed demand response provider will have 2 x $40 = $80 more if it does not consume a MWh of electricity than if it consumes that MWh. **In other words, the imputed demand response provider would be paid twice under the Commission's proposal.**[123]

With regard to appropriate compensation, EPSA asserts the Commission simply cannot ignore the fact that in addition to Professor Hogan, there are other

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[123] Attachment 1, Hogan Policy Paper at 5, (emphasis added).

highly regarded economists, including the PJM and NYISO market monitors, who do not support compensation of full LMP in all hours as the appropriate compensation for DR. For example, in reacting to the DR Suppliers proposal in the PJM proceeding to pay all DR resources full LMP in all hours, PJM's independent market monitor Joseph E. Bowring stated such a proposal "is inconsistent with the fundamental economics, and, if accepted by the Commission would over compensate participants in PJM's Economic Program, degrade the efficient operation of the energy markets and provide no offsetting social benefit."[124] In the 2009 State of the Market Report for NYISO (NYISO 2009 SOM Report), the external market monitor David Patton supports the NYISO's plan to develop a real-time DR program with the following proposed settlement recommended for curtailed load: (1) pay the price-responsive customer the Locational Based Marginal Price ("LBMP"); (2) charge the LSE serving the customer the LBMP; and, (3) the LSE continue to charge the customer the applicable retail rate.[125] As stated in the NYISO 2009 SOM Report, this compensation for DR resources (i.e.,

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[124] PJM MMU Answer at 1-2, Docket No. EL09-68, (filed October 16, 2009).

[125] 2009 State of the Market Report, New York ISO Electricity Markets at 14, David Patton, Potomac Economics, April 2010, (2009 NYISO SOM Report). The report is available here: http://www.nyiso.com/public/webdocs/documents/market_advisor_reports/2009/2009_NYISO_SOM_Final_4-30-2010.pdf.

LBMP—the applicable retail rate) "provides efficient incentives to the customer and avoids uplift costs."[126]

It is worth noting here that it is not only economists who support payment of LMP minus the DR resource's avoided costs of consumption. Indeed, in the instant NOPR, the Illinois Commerce Commission ("ICC") filed comments stating "that the ICC supports the payment of LMP minus the retail rate (i.e., LMP – RR) for economic demand response in the wholesale market because it provides load serving entities with the right incentives to allow the participation of economic demand response resources."[127] The ICC Comments further discuss that

> [i]n pure economic terms a reduction in demand is fundamentally different from an increase in supply. Demand reductions and supply increases are not only intuitively divergent, but treating them equivalently has material implications The ICC believes that demand response should be incentivized and participants should be fairly compensated, but these comments show that they are not particularly comparable with generation supply.[128]

The ICC Comments discuss the implications of three methods of compensation for demand response—zero payment, LMP minus the retail rate, and LMP. With

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[126] *Ibid.*

[127] Comments of the Illinois Commerce Commission at 1, Docket Nos. RM10-17-000 and EL09-68-000, (filed May 6, 2010) ("ICC Comments").

[128] *Id.* at 2.

respect to a payment of zero dollars (which it deems "in theoretical terms" the economically efficient compensation for reductions in demand in a marketplace), the ICC "affirms the principle that implementing dynamic retail rates would be a more effective mechanism to achieve the goal of efficient electrical resource utilization than would demand response resources participating through supply offers in wholesale markets."[129] The ICC Comments present a number of compelling arguments in support of LMP – RR as the appropriate payment for economic demand response in the wholesale market, including noting such payment "is also consistent with the highest level of economic efficiency under the *presumption that demand reductions are comparable to generation of energy.*"[130]

Additionally, in the MISO Order No. 719 compliance proceeding referenced by the NOPR, MISO also proposes compensation at settlement to Aggregators of Retail Customers (ARCs) through a two part transaction process resulting in payment of LMP minus the applicable retail rate—and as noted previously herein, the Organization of MISO States (OMS) supports this proposal as the appropriate compensation for ARCs.[131] The MISO compliance filing explains the comparability of its proposal as follows:

> it is appropriate, and just and reasonable to pay ARCs the LMP, net of MFRR [the Marginal

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[129] *Id* at 7-8.

[130] *Id.* at 8-11.

[131] *See* Footnote 38 above.

Foregone Retail Rate]. In order to treat demand response comparably with a power producer the Midwest ISO must pay both of them the same price for each MWh of energy that the resource "injects" into the transmission system. That is why the Midwest ISO pays the LMP to both generation and demand response resources, including ARCs.

The MFRR also is subtracted from LMP to achieve comparability. When a power producer injects energy into the Transmission System, it owns that Energy because it either produced the Energy with its own Generator or purchased it from another source. In contrast, when an ARC injects energy into the Transmission system, it is not actually delivering additional energy, but rather reallocating Energy that is already present in the system, or reducing the need for an incremental amount of MW to support the energy balance. What the ARC is actually selling is the right of a retail customer to consume that Energy at a price set by the customer's retail tariff. Since the retail customer's meter does not record Energy that the customer does not consume, the customer avoids paying for the Energy it has made available for sale by the ARC. Consequently, the ARC should pay for that Energy in order to sell it to someone else. [132]

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[132] Midwest ISO, Filing re Aggregators of Retail Customers at 15-16 and Robinson Testimony at 13-15, Docket No. ER09-1049-002, (filed October 2, 2009).

Of interest, the earlier Hogan Paper submitted in the PJM proceeding included a similar mechanism for implementing a demand response program, which envisioned that each demand response transaction would be unbundled into an electricity purchase and an electricity sale, thereby providing incentives for efficiency.[133] As articulated by Professor Hogan in the attached Policy Paper, "The separation of the transaction into a purchase and a sale clarifies the underlying economics and makes it clear that in order to provide incentives for an economically efficient amount of demand response, demand response providers must be charged for the electricity they would have consumed, in addition to being paid the LMP for not actually consuming that electricity."[134]

Another significant economic concern with the NOPR proposal was flagged by Commissioner Moeller, who noted that "[t]he approach embraced in the NOPR may also lead to a situation where residential ratepayers could be subsidizing other classes of service while unable to participate themselves in demand response programs. Absent attention to these issues, it will be difficult for any proposal to place generation and demand response on a precisely level playing field."[135] In a similar vein, Professor Hogan focuses

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[133] *Motion to Answer and Answer of the Electric Power Supply Association with White Paper by Professor William W. Hogan*, Docket No. EL09-68-000 (October 30, 2009) Hogan White Paper, pp. 19-21. (Emphasis added.)

[134] Attachment 1, Hogan Policy Paper at 16.

[135] Commissioner Moeller Statement at 5.

on the potential for "significant and adverse effects on many consumers of electricity under various scenarios . . , which are discriminatory, and which simply may not be sustainable in the long term"[136] with respect to the market inefficiencies arising from the NOPR proposal. Specifically, Professor Hogan discusses an important consequence posed by the proposed DR compensation, which could actually result in demand response programs that induce some consumers to stop or reduce participation in RTO-administered markets.[137] He offers a potential scenario that would lead to generation moving "behind the meter," whereby a nearby generator such as distributed generation would provide electricity directly to serve the load. There is certainly nothing wrong with distributed generation. The issue is the extent to which, if at all, other consumers on the grid should subsidize those who engage in distributed generation off the grid. The electricity in this scenario would not flow into or out of the RTO-administered markets, and from the RTO perspective, results in the appearance of net demand reductions, when in fact none has actually occurred. The result is a shift in costs to other, likely smaller consumers, and ultimately, a reduction in participation and increased costs to remaining consumers buying from the RTO-administered market.[138] Professor Hogan points out that,

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[136] Attachment 1, Hogan Policy Paper at 6.

[137] *Id.* at 6-11.

[138] *Ibid.*

> [t]here are likely to be many consumers who simply do not have the capability to enter into these behind-the-meter arrangements and would continue to purchase their electricity in the RTO-administered markets. This group of consumers, which is likely to include load-serving entities selling to a disproportionately large number of residential and small commercial customers whose operations are not of sufficient size and scope to make it worth their while to incur the fixed costs associated with moving generation behind the meter, must pay not only for electricity generated for their own use, but also for electricity generated for consumption by other (generally larger) consumers for whom moving generation behind the meter is cost effective, since consumers who move generation behind the meter will pay approximately zero for their electricity.[139]

This is not simply an academic or theoretical exercise in considering potential scenarios under the NOPR's overly broad compensation proposal. In fact, as pointed out earlier, it is fully contemplated and an expected outcome under "full LMP in all hours" compensation as articulated in affidavits filed by the Demand Response Supporters ("DR Supporters") coalition in the now-terminated PJM proceeding. Significantly, Allen M. Freifeld's affidavit in support of the DR Supporters' proposal for full LMP in all hours, discussed that

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[139] *Id.* at 10.

> Demand response sometimes takes the form of a customer curtailing his take of grid power and running his own behind the meter generation. Adequate compensation will further the objective of increasing such deployments. And such deployment should be encouraged for a variety of reasons.[140]

> The service that the DR customers are selling is curtailment of energy on the grid, that is, their ability to reduce the level of generation required to keep the grid in balance. They do this by substituting for what otherwise would be consumption of power from the grid, by either operational changes that temporarily reduce overall consumption, a shift in consumption through storage activities, production of power from an internal source or, increasingly, a combination of all three.[141]

A separate affidavit on behalf of the DR Supporters' proposal for full LMP compensation was provided by Ron Belbot, who is an employee of Severstal Spar-

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[140] Affidavit of Allen M. Freifeld On Behalf of Demand Response Supporters at 13, Docket No. EL09-68-000, (filed September 16, 2009).

[141] Reply Affidavit of Allen M. Freifeld On Behalf of Demand Response Supporters at 6, Docket No. EL09-68-000, (filed November 12, 2009). In this situation, if the LMP is $50, it would be in the interest of a consumer to run behind-the-meter generation that costs $95, as the net price of $45 after taking the DRP payment from the RTO into account is less than the cost of buying from the market at $50.

rows Point.[142] Sparrows Point is a steel plant and a Load Serving Entity in PJM, and "purchases all of its power from PJM either on the Day-Ahead or Real-Time Spot Markets."[143] Sparrows Point participated in the PJM Economic Program until the incentive program was allowed to sunset in 2007 and while it was participating, was being self-scheduled.[144] Sparrows Point has a "behind-the-meter" generating station, and of note, is the largest single consumer of electricity in the state of Maryland.[145] Mr. Belbot noted that

> Sparrows Point's **curtailments were produced by increasing generation with purchased fuels at our internal powerhouse** and by curtailing various operations in the plant. When the locational marginal price in the BC zone is above the strike price for generating power on either natural gas or fuel oil, the plant will still increase generation and reduce the amount being purchased, but the savings created by the avoided cost of power is not sufficient to warrant curtailing any of the operation in the plant without the addition of the payment. [146]

EPSA stresses that such an industrial customer has every right to self-generate when it makes economic

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[142] Affidavit of Ron Belbot on Behalf of Demand Response Supporters, Docket No. EL09-68-000, (filed September 16, 2009). (Emphasis added.)

[143] *Id* at 1.

[144] *Id.* at 1 and 3.

[145] *Id.* at 1.

[146] *Id.* at 2.

sense to do so. However, as the Belbot Affidavit points out, DR providers and supporters want other consumers including residential ratepayers to pay for them to do so even when the avoided cost of power is not sufficient to warrant doing so. There is no discussion in the NOPR whatsoever as to the basis for finding such a cross-subsidy just and reasonable, yet the Commission was aware from the PJM proceeding that demand response providers and supporters expressly contemplated such a subsidy. Furthermore, there is nothing in the NOPR to assess the environmental impacts from switching to off-grid power generated with fuels that produce more greenhouse gases and other air emissions than electricity from the regional energy market. This is relevant in that there is no limitation in the NOPR on the types of off-grid power that would qualify. There is also no discussion as to whether curtailing plant operations over and above that justified by the avoided cost of power would produce adverse economic consequences, including job losses and lower employment income, in the affected regions, including at the expense of those commercial and residential customers financing the cross-subsidy through higher power prices.

To further reiterate concerns with the NOPR, Professor Hogan references to a 1997 Commission ruling which mandated a congestion management procedure in PJM that gave market participants incentives to transact outside the PJM market. The end result was that so many generators in PJM's western and central regions self-scheduled "that PJM found itself without any resources in those regions that it

could dispatch downward, causing PJM to declare a minimum generation emergency (which permitted PJM to curtail transactions) on August 22, 1997, *during the system peak.*"[147] Professor Hogan summarizes,

> The central failing of the congestion management procedure that the Commission directed PJM to apply in 1997 was that it did not charge market-clearing prices for access to transmission facilities when those facilities were congested. By making it cheaper for generators to gain access to those facilities by self-scheduling than by bidding into the market, the Commission made it impossible for PJM to use the market to allocate access to those facilities. **Similarly, in this proceeding, by mandating subsidies that could make it cheaper for certain consumers to consume electricity if they purchase it outside the market than if they purchase it in the market, the Commission could make it impossible for RTOs and ISOs to operate their markets, if too many consumers elect to purchase their electricity outside those markets. The market rules in place in the RTO-and ISO-administered markets have, in general, been carefully crafted to give market participants incentives to act in a manner that is consistent with market efficiency. If the Commission now chooses to mandate procedures that are fundamentally inconsistent with market efficiency, the Commission runs the risk of undermining the**

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[147] *Id.* at 11 and n.12.

operation of those markets in a manner reminiscent of 1997.[148] (Emphasis added)

Professor Hogan's Policy Paper demonstrates that the NOPR proposal to pay DR resources full LMP in all hours could result in outcomes that are unjust, unreasonable and unduly discriminatory. Further, Professor Hogan's paper reflects that the proposal is not necessary to induce efficient behavior and would instead encourage inefficiently large amounts of demand response. The ultimate costs of such an outcome would likely fall disproportionately on smaller consumers and the DR programs resulting from the NOPR may be unsustainable given the incentives to transact outside the ISO/RTO wholesale markets. Professor Hogan recommends that the Commission "focus upon compatible demand response programs, which would address those specific circumstances when consumers in a given organized market do not have an incentive to act efficiently ,"[149] and EPSA concurs that such a targeted, measured approach, following a broader evaluation of DR participation across all relevant ISO/RTO markets, is the more appropriate manner in which to proceed.

C. Considerations for Mandating One Generic Pricing Mechanism

Though the NOPR recognizes that each RTO is developing demand response programs on a regional basis, there remains concern that, "some existing, in-

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[148] *Id.* at 11-12.

[149] *Id.*, at 17.

adequate compensation structures have hindered the development and use of demand response."[150] Thus, the NOPR proposes that a just and reasonable solution would be to mandate a generic price for DR across all RTOs.[151] EPSA agrees with Commissioner Moeller's statement that "a standard payment could have unintentional effects on both demand response participation and the efficient operation of the organized markets over the longer term."[152]

Deference to regional market developments has been the defining approach of the Commission regarding the progress of the organized wholesale electricity markets. Over the history of the Commission's rate approval and pricing mechanism programs, the Commission has continually found that allowing for regional variation and development meets the just and reasonable standard. The instant NOPR proposal to standardize a single market design element across the ISO/RTO regions is counter to the Commission's past approach and is inappropriate, based both on Commission precedent and impacts on the markets. Further, given that the DR products differ greatly across the ISOs/RTOs, both in the wholesale energy and other markets, it may be counterproductive to attempt to require a standardized pricing mechanism.

Since the inception of ISOs/RTOs in Order No. 2000, through the failed experiment with Standard

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[150] *Id.* at P 9.

[151] *Id.* at P 13.

[152] Commissioner Moeller Statement at 2.

Market Design (SMD) and even in recent capacity market design proceedings, the Commission has continually found that regional deference is an integral part of finding rate designs and pricing mechanisms just and reasonable. To wit, Order No. 2000 noted:

> [T]he Commission is not proposing a "cookie cutter" organizational format for regional transmission institutions or the establishment of fixed or specific regional boundaries under section 202(a) of the FPA. We also establish an "open architecture" policy regarding RTOs, whereby all RTO proposals must allow the RTO and its members the flexibility to improve their organizations in the future in terms of structure, operations, market support and geographic scope to meet market needs. In turn, the Commission will provide the regulatory flexibility to accommodate such improvement.[153]

Even though Order No. 2000 did not propose a "cookie cutter" approach, in 2002, the Commission explored the possibility of a Standard Market Design (SMD).[154] At the time, EPSA was supportive of the SMD approach and participated in all of the technical conferences and comment periods associated with that pro-

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[153] *Order No. 2000: Regional Transmission Organizations*, 65 Fed. Reg. 809 (Jan. 6, 2000), FERC Stats. & Regs. ¶ 31,089, 31,061 (2000), p. 6.

[154] *Notice of Proposed Rulemaking Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design*, Docket No. RM02-1-000 (July 31, 2002).

ceeding.[155] Ultimately, as various ISOs/RTOs evolved, both the Commission and industry realized that standardizing a market design was untenable because regional differences (including fuel mixes, peak seasons, demand and market size variation,) were too vast. In the 2005 Order terminating the SMD proceeding, one of the main reasons the Commission listed for not adopting the 2002 NOPR was that "the proposed rule was too prescriptive in substance and implementation and did not sufficiently accommodate regional differences."[156]

In more recent years, the Commission has allowed for standardization of some aspects of ISO/RTO market rules, including reliability measures.[157] While EPSA continues to support the proposition that there

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[155] *Rulemaking Comment of the Electric Power Supply Association*, Docket No. RM01-12-000 (September 18, 2002).

[156] *Termination Order: Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design*, Docket No. RM01-12-000 (July 19, 2005), at P 3.

[157] Indeed, since the inception of RTOs, reliability has been one of the main aspects on which the Commission envisioned as much standardization as possible. Order No. 2000 stated: "The Commission's staff found that the market institutions were not adequately prepared to deal with such a dramatic series of events. Regarding regional transmission entities, the staff report observed: "The necessity for cooperation in meeting reliability concerns and the Commission's intent to foster competitive market conditions underscores the importance of better regional coordination in areas such as maintenance of transmission and generation systems and transmission planning and operation." (pp. 19-20; Order No. 2000 quoting an earlier FERC staff report).

should be greater standardization across markets on reliability issues, market design issues must necessarily be developed on a regional basis. Further, honing in on one market pricing element while allowing differences across all other pricing facets is patently unreasonable and unworkable, certainly without further analysis not found in the NOPR. This seems to be underscored in the instant NOPR itself which notes that payment to DR resources of full LMP in all hours "is the correct approach at this time, " suggesting that this may not always be the case, after sufficient technology to enable demand response has been added to the grid, for instance.[158]

Pricing mechanisms and rate approvals continue to be properly and necessarily afforded regional deference. Order No. 719 is the most recent Commission-issued national policy directive that affirms the Commission's commitment to allowing price formation and compensation mechanisms to be regionally developed, in particular those for price responsive demand response, in fact. Order No. 719 recognized that ""Absent a single national power market, the development of regional markets is the best method of facilitating competition within the power industry."[159] Specifically, with regard to price formation and demand response compensation, Order No. 719 mandated that the ISOs/RTOs regionally develop mecha-

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[158] NOPR at P 19.

[159] Order No. 719: *Wholesale Competition in Regions with Organized Electric Markets*, 125 FERC ¶ 61,071, Docket Nos. RM07-19-000 and AD07-7-000 (October 17, 2008), at P 10.

nisms, declining to prescribe a national uniform methodology.[160] The Commission further stated in Order No. 719 that changes to accommodate demand response and price formation directives are linked to regional market rules, which also may need to be altered.[161] Indeed, each market has different DR products which participate in differently structured energy, ancillary service and capacity markets.[162] Order No. 719 stated that it was not even appropriate to set standardized technical requirements for DR.[163] Thus, it would be equally inappropriate for the Commission in the instant proceeding to develop standardized pricing and compensation mechanisms, as the products themselves are not standardized. For

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[160] *Id.* at P 50: "Each RTO and ISO is unique, and the Commission hesitates to impose a uniform definition. Each RTO and ISO therefore should establish policies and procedures in cooperation with its customers and other stakeholders that ensure that demand response resources are treated comparably to supply-side resources."

[161] *Id.* at P 166.

[162] Some of these markets, such as the PJM capacity market, have shown significant increases in participation by DR resources, who have received a significant level of compensation ($303 million in 2009, reflecting a 114% increase from 2008). National action in this case may stunt DR resource growth. *See*: Monitoring Analytics, State of the Market Report for PJM at 111 (March 11, 2010).

[163] Order No. 719 at P 59: It is not appropriate in this rulemaking to develop a standardized set of technical requirements for demand response resources participating in ancillary services markets. Instead, the Commission will allow each RTO and ISO, in conjunction with its stakeholders to develop its own minimum requirements.

example, each RTO has a set of unique DR products, compounded by the varying markets in which those products can participate within that RTO. DR products are offered to market participants in similar, yet slightly different, ways. For instance, PJM has seven different DR products available across the wholesale markets it operates.[164]

With respect to the non-RTO regions, there is less known regarding participation by DR resources in the traditional, vertically integrated bilateral markets other than relying on these entities' own reports on their own programs. This lack of transparency seems at odds with the Commission's goal of increasing DR participation nationally. Additionally, the focus on the organized wholesale markets with no apparent or stated intention to address demand side resource rates in the cost-based non-RTO markets raises questions as to this concedes the point that DR raises retail jurisdictional concerns. EPSA submits that proposing

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[164] In addition to PJM's seven different types of demand response products (three of which are energy market products), the other RTOs have developed completely different product sets. ISO New England has nine separate DR products, four of which provide energy services; MISO and NYISO both have seven DR products with three in the energy markets; and, the California ISO has two load programs, one that operates in the energy market and the other the offers a reserve product. Note that some of these products are at various stages of development. California's participating load program, for example, is slated to begin in August 2010. *Draft National Action Plan on Demand Response*, Docket No. AD09-10-000 (March 11, 2010), p. 100-102. Citing information adapted from the ISO/RTO Council.

standardization in certain markets, but not applying the requirements to others is inappropriate,

Finally, there have been several recent orders in regional proceedings that affirm the Commission's policy that regionally developed mechanisms for pricing and compensation matters are part of FERC's ultimate just and reasonable determination. For example, in a 2008 ISO New England proceeding, the Order noted:

> The Commission has consistently recognized that regional differences may be recognized in its analysis of the just and reasonableness of transmission organization proposals, and the fact that other RTOs have enacted (or failed to enact) a particular market rule is not dispositive of the justness and reasonableness of ISO-NE's market rule.[165]

This need for regional variance is affirmed in numerous FERC orders for almost every aspect of market design—including capacity market rules, scarcity pricing proposals, long-term firm transmission rights, and resource adequacy.[166] In its application of the Feder-

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[165] *Order Accepting Filings and Requiring Compliance Filings of ISO New England Inc and New England Power Pool*, 125 FERC ¶ 61,102, Docket No.ER08-1209-000 (October 28, 2008), at P 97.

[166] *See Midwest ISO*, 116 FERC ¶ 61,292, at P 53 (2006); *Long-Term Firm Transmission Rights in Organized Electricity Markets*, Order No. 681, 71 Fed. Reg. 43,564 (August 1, 2006), FERC Stats. & Regs. ¶ 31,226, at P 100 (2006); *Southwest Power Pool, Inc.*, 110 FERC ¶ 61,031, at P 22-23 (2005); *Midwest Inde-*

al Power Act mandate that the Commission establishes just and reasonable rates, the Commission has noted that regional differences are a determinant in making a just and reasonable finding. It would therefore be contrary to prior Commission orders and the FPA to move forward with the Commission's proposal to standardize the pricing/compensation mechanism for demand response in the instant proceeding.

Additionally, the standardization of demand response compensation is inappropriate in the context of the overall ISO/RTO markets. As supported by FERC in numerous proceedings, major pricing elements in these markets differ by region. This includes such central pricing elements as how LMP is developed, whether and how periods of supply scarcity are defined and compensated, and whether and how resource adequacy is maintained through a forward capacity market. If these critical compensation methods are not standardized across the ISO/RTO markets, it calls into question what is different about energy market demand response, and what affect standardizing that discrete market would have on the other pricing components of the organized markets. In a similar vein, operational seams between markets remain, after nearly ten years of operation, indicating that these markets do operate idiosyncratically. As explained by ISO New England President and CEO Gordon Van Welie, converging the northeastern power markets operationally is occurring slowly, "There is no

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pendent Transmission System Operator, Inc., 102 FERC ¶ 61,196, at P 43 (2003).

silver bullet on seams issues We should selectively work on the most problematic seams first."[167] With this in mind, it is questionable to move forward on the standardization of one discrete pricing element. These are important concerns and questions that are not addressed in the NOPR, but cannot be overlooked.

EPSA is supportive of the development and participation of demand response in the energy markets. The goal of the NOPR to facilitate demand response by removing barriers to participation of DR resources in ISO/RTO markets is laudable.[168] However, the NOPR's reference to DR and generation comparability requirements of Order Nos. 890, 890-A and 719 to justify full LMP in all hours is misguided. While these comparability requirements were generic policy actions applicable to all ISOs/RTOs and intended to facilitate DR participation across the organized wholesale electric markets, it is important to note that, consistent with its past approach, the Commission outlined certain principles in these orders, but allowed for regional differences in the manner that each ISO/RTO demonstrated compliance with these new requirements. Furthermore, Order No. 719 included pricing reforms to ensure "that the market price for energy reflects the value of energy during an operating reserve shortage."[169] To accomplish this goal, the Commission set out six price formation criteria, and offered

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[167] "NE Power Markets Will Converge: ISO-NE CEO," Electric Power Daily (April 28, 2010).

[168] NOPR at P 5 -6 and n.17.

[169] Order No. 719 at P 247.

four suggested approaches to pricing reform during operating shortages, though ISOs/RTOs could make a showing that their existing or an alternative approach achieves the same objective. The Order stated, "We require that each RTO and ISO address in its compliance filing how its selected method of shortage pricing interacts with its existing market design."[170] This approach to ensuring comparability within the context of regional markets should be the guiding principle for the compensation of economic demand response as well.

D. One Megawatt of Demand Reduction Is Not Always Equal to One Megawatt of Supply

In response to what can be deemed to be a critical foundation of the NOPR, one megawatt of demand is not always the same as one megawatt of supply. When this premise is deconstructed, the notion that demand and supply consistently represent a one-to-one equation across all operating and economic conditions is unsustainable. The wholesale electricity grid must be understood as a huge, complicated machine—or a series of interconnected huge, complicated machines—with many moving parts that enable it to run reliably. This is a function of the physics of electricity in the absence of its storage on a wide scale.

While the reduction of required output—load reduction—does benefit the ability of the system to run at peak conditions (and may lower prices for the remaining output in the short run), it cannot be substi-

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[170] Order No. 719 at P 204.

tuted wholly for supply in all cases. At some point, there is a level of electricity demand below which consumers will not go economically if acting on accurate price signals, or which is inconsistent with maintaining reliability. At a minimum, at such points an additional MW of DR is not equal to one MW of generation.

For instance, PJM recently issued a news release to note that it is forecasting a peak demand of 135,750 megawatts of electricity this summer, a figure that includes an assumed six percent demand reduction due to voluntary reductions by consumers (approximately 8,525 MW, the equivalent of ten large power plants). While participation by demand in numerous markets is commended and touted by PJM, the news release also importantly notes that, "The PJM region includes 51 million people and 20 percent of the U.S. economy."[171] Therefore, a critical element to meeting a threshold level of physical supply in order to keep the lights on for the 51 million people who reside in PJM includes 162,903 MW of available. At some level of market share, demand cannot replace supply without severely hampering the reliable delivery of electricity that is needed by consumers.

Demand response differs from generation resources in a number of ways. It has been well documented, even by the Commission, that the two products are not

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[171] PJM News Release, "Demand Response to Play Significant Role in Meeting PJM's Higher summer Peak Electricity Use: Grid Operator Foresees Adequate Power Supplies for Summer," (May 5, 2010). Available here: http://www.pjm.com/About-PJM/Newsroom/announcements-and-news-releases.aspx

conceptually the same.[172] While they may be comparable, they are not equal. One megawatt of demand response is a different product from one megawatt of traditionally-generated supply—in fact, economic demand response in the energy market may not in fact be definable as a resource "product" and has none of the operational attributes of generation. In terms of value, the action of reducing load (whether via behind the meter generation or physical reduction of consumption) can only be equated in value to supply in the energy market if the end customer/DR provider has first obtained title to the energy it seeks to sell by deferring its own consumption or activating its behind the meter generation. The simplest example is reduction of metered load by virtue of behind-the-meter generation. The generation behind the meter should be treated equally to other generation. But this would mean that in order for the behind-the-meter megawatt to be paid the full LMP as DR, it would be necessary for the metered load to be increased to reflect the amount of the load reduction. Otherwise, the behind-the-meter generator would be paid the retail rate (avoids retail charges while maintaining load) and it would be credited also as a wholesale energy sale. Similarly, a load reduction (decrease in consumption) does not provide electrons to any other load, it simply allows the marginal electron to serve a different customer. While it may be reasonable to permit the load to avoid the full LMP by avoiding the retail rate and getting a payment for the amount by which the LMP

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[172] Order No. 719 generally.

exceeds the retail rate, paying the full LMP plus the customer's value in avoiding the retail rate would provide greater compensation to the customer than is being paid to generation (and create uplift). These thresholds, reliability impacts, and product characteristics have not been addressed in the NOPR, even though they present critical issues that must be addressed when contemplating first the integration, then the compensation, of DR into the wholesale energy markets.

As stated previously and in numerous other venues, EPSA acknowledges and supports that both demand and supply-side resources are important components of a healthy competitive market, and should be treated appropriately consistent with that objective. The Commission has typically encouraged ISOs/RTOs to use demand response as they would use generation "where it is technically capable,"[173] inferring that there are certain technical characteristics of demand response that renders at least some DR resources technically incapable of acting as traditional dispatchable supply-side resources, thus acknowledging that any given MW of demand response is not always equal to a MW of supply.[174] For the purposes of reliability, the Commission has noted that:

> New demand response resources are typically not included as potential solutions to transmission ad-

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[173] Order No. 719 at P 16.

[174] 2007 Assessment of Demand Response and Advanced Metering (September 200 7), p. i.

> equacy problems. System planners do not consider demand response equally when they examine options for dealing with transmission inadequacies. If they do consider demand response, it is as a temporary solution until a permanent transmission enhancement is in place.[175]

A new demand response unit is not the same as a new generating unit. They perform different functions and must be modeled into the system in different ways. One is the opposite of the other; as such, where a generation product is planned and scheduled to meet statutory NERC reliability criteria, many demand response programs provide last-minute reserves that are not part of reliability planning processes. Additionally, while generators are subject to an extensive array of NERC Mandatory Reliability Standards, DR providers are not subject to any NERC standards whatsoever. If a unit of demand were always truly equal to a unit of supply, DR would surely be subject to all of the NERC Mandatory Reliability Standards that apply to generators. While both supply and demand are important resources, they are not always equal in capability and thus not in value.

Further, not every type of demand response product has the same value as other demand response products. The value of a demand response product depends on a number of different variables, including which market the DR is bidding into, the time of use,

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[175] 2007 Assessment of Demand Response and Advanced Metering (September 2006), p. x.

the time it takes to call on the demand response product and the predictability of that product for planning purposes. It is precisely for this reason that various ISO/RTOs have multiple demand response markets, options and products.[176] What is notable, however, is that there are serious differentiations even among the various products participating as economic energy resources. For example, within ISO New England's energy market, there are four different demand response products, including three that have an "effectively instantaneous" response time and one that has a 10 to 30 minute response time.[177] Among those four demand response products, two participate in the day-ahead load response program while the other two participate in the real-time energy markets. Value differences can be derived from both different response times and the different energy markets in which they participate. While the NOPR lacks significant detail in the demand response products or obligations that would be eligible for compensation of full LMP in all hours, the New England energy market demand response options indicate that even in one re-

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[176] For example, the New York ISO, even as it is a single-state ISO, operates seven different demand response products that participate in energy, reserve, regulation and capacity markets. Source: *Draft National Action Plan on Demand Response*, Docket No. AD09-10-000 (March 11, 2010), p. 100-102. Citing information adapted from the ISO/RTO Council.

[177] *Draft National Action Plan on Demand Response*, Docket No. AD09-10-000 (March 11, 2010), p. 100-102, citing information adapted from the ISO/RTO Council.

gion there is not one pricing scheme that accurately reflects the value of various demand-side resources.

The New England example cites the DR energy products in just one regional market. Each market will have individually tailored energy market DR products which provide different values, in addition to numerous different DR products in other markets (capacity, regulation and reserve/emergency). The differences in value represent varying capabilities and interactions with the electricity grid. The proposed generic compensation proposal in the NOPR does not reflect this complex market structure, and in standardizing one particular market element may distort the price levels and participation incentives in the related non-energy markets.

Additionally, while not only is one MW of demand not always equal to one MW of supply, one MW of economic demand in a particular RTO may not be equal to one MW of economic demand in another RTO. A report by the Brattle Group, titled "Fostering Economic Demand Response in the Midwest ISO" (MISO Brattle Report) may be particularly helpful in this proceeding, as the Commission's NOPR seems to primarily address economic demand response bids.[178] The MISO Brattle Report not only chronicles the different types of dynamic pricing within MISO and how that pricing interplays with various demand re-

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[178] *Fostering Economic Demand Response in the Midwest ISO*, prepared by the Brattle Group for the Midwest ISO. (December 30, 2008). Available here: http://www.brattle.com/_documents/uploadlibrary/upload729.pdf.

sponse models, but also compares the products offered in MISO to those offered in other ISOs/RTOs. As that report demonstrates, the pricing schemes within one ISO/RTO can interplay with demand response in a host of innovative and complimentary ways; it also demonstrates how different MISO's pricing schemes and demand response products are from other ISOs/RTOs.[179] Proscribing one pricing mechanism for demand response and forcing it to fit in with the other pricing mechanisms for all other products already in place would be prohibitive and possibly undermining the generally thoughtful stakeholder-constructed products and programs already in place in organized markets.

In sum, the instant NOPR is overly simplified and puts a host of products on equal footing when they clearly provide varying degrees of value. Demand response is neither the same in all RTOs/ISOs, nor is it always equivalent across different types of demand response products, nor is one megawatt of demand response always comparable to one megawatt of traditionally generated supply. And yet, the NOPR would compensate an undefined economic DR product equally in all markets at all times (full LMP in all hours). For demand response programs and products to thrive, any Commission-approved compensation structure should consider, properly account for and incorporate all of those differences.

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[179] *Id.*, See Charts beginning on p. 49.

While economic demand response brings value to the grid, full LMP in all hours without any adjustment for the avoided cost of consumption would not constitute providing demand response with treatment comparable with that of generators; it represents a subsidy even though the Commission has clearly stated that it "does not favor granting preference for demand response."[180] The instant NOPR does not propose to make one megawatt of demand equal to one megawatt of supply, it proposes to make one megawatt of demand response worth more than one megawatt of supply. While well intended, the NOPR's proposal is flawed; it fails to recognize that demand response consists of an array of regionally-tailored unique products that should be considered by the Commission on a case-by-case basis in order for those products and the markets in which they participate to thrive and for the Commission to fulfill its mission of "ensur[ing] comparable treatment for demand response resources"[181] within the FPA's requirements.

V. CONCLUSION

Wherefore, for the foregoing reasons, EPSA respectfully requests that the Commission consider these comments in determining further action in this proceeding. Assuming that the jurisdictional and economic questions raised by the NOPR can be addressed, and specific provisions on issues such as veri-

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[180] Order No. 719 at P 16.

[181] 2009 Assessment of Demand Response and Advanced Metering (September 2009), pp. 4-5.

fiability are added to the proposed tariff language, EPSA submits that while full LMP in all hours is not just and reasonable, a pricing mechanism based on LMP with the appropriate offset reflecting the avoided cost of consumption is a sound basis to proceed with the development of compensation principles for economic demand response.

Respectfully Submitted,

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May 12, 2010

Implications for Consumers of the NOPR's Proposal to Pay the LMP for All Demand Response

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May 12, 2010

Implications for Consumers of the NOPR's Proposal to Pay the LMP for All Demand Response

William W. Hogan

May 12, 2010

Summary

The Federal Energy Regulatory Commission has proposed a rule for compensation of demand response acting as a resource in the electricity energy market. The rule would pay the full Locational Marginal Price (LMP) for all types of demand response. This pricing rule would be appropriate in some cases and not in others. The analysis distinguishes among three general types of demand response.

- **Real-time Pricing Demand Response.** Consumers are paying the applicable LMP for their marginal consumption.
- **Explicit Contract Demand Response.** Consumers purchase a fixed quantity of electricity but consume less than the purchased amount and sell back the difference.
- **Imputed Demand Response.** Consumers have an estimated consumption baseline and the difference between actual consumption and the baseline is the imputed demand response.

The first two types of demand response have a straightforward framework for using the applicable LMP. However, the important case where the Commission's policy would be problematic is the likely ubiquitous circumstance of imputed demand response

against an estimated consumption baseline. For this important case, full payment of the applicable LMP for the difference between actual consumption and the baseline would not be appropriate. The proposed rule would create an incentive for consumers to avoid real-time pricing and explicit contract demand response in preference for the higher net payments under imputed demand response. There would be further incentives to move generation behind the meter in the organized markets. The higher costs created would be born by other consumers less able to participate in the imputed demand response program, and would likely be unsustainable.

The Commission has available a number of alternatives that would better serve to support efficient demand response without creating perverse incentives or unintended consequences. The details would depend on many factors of electricity tariffs, but the essence would be to put the net payments for imputed demand response on an equal footing by emulating the payments under an explicit contract.

Implications for Consumers of the NOPR's Proposal to Pay the LMP for All Demand Response

William W. Hogan[i]

May 12, 2010

Introduction

While many advances have been made in the development of competitive electricity markets in the decade since they were originally implemented, there remain aspects of those markets that are ripe for improvement. One such area is the treatment of demand response. There is little question that current market rules may give demand response providers incorrect incentives to consume electricity, and that as a result, the amount of demand response that is provided is inefficient. In its March 18, 2010 Notice of Proposed Rulemaking,[1] the Federal Energy Regulatory Commission ("FERC" or the "Commission") addresses this concern, by proposing standard rules for the compensation of demand response resources that would apply to all energy markets administered by Regional Transmission Organizations ("RTOs") and Independent System Operators ("ISOs").

The Commission's proposed rule would pay the full LMP for all types of demand response in the energy market. The present paper addresses further the impacts of the Commission's proposed policy and demonstrates that the pricing rule would be appropriate in some cases and not in others. The analysis distin-

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[1] 130 FERC ¶ 61,213 (2010) ("NOPR").

guishes among three general types of demand response.

- **Real-time Pricing Demand Response.** Consumers are paying the applicable LMP for their marginal consumption.
- **Explicit Contract Demand Response.** Consumers purchase a fixed quantity of electricity but consume less than the purchased amount and sell back the difference.
- **Imputed Demand Response.** Consumers have an estimated consumption baseline and the difference between actual consumption and the baseline is the imputed demand response.

The first two types of demand response have a straightforward framework for using the applicable LMP. However, the most important case where the Commission's policy would be problematic is the likely ubiquitous circumstance of imputed demand response against an estimated consumption baseline. For this important case, full payment of the applicable LMP would not be appropriate, but the Commission has available a number of alternatives that would better serve to support efficient demand response without creating perverse incentives or unintended consequences.

The PJM proceeding subsumed by this NOPR included a paper submitted to the Commission as part of the

filing by the Electric Power Supply Association.[2] The analysis in that paper continues to apply and is addressed to issues that appear again in the NOPR. As discussed further here, the Commission's proposal is grounded in a misunderstanding of the outcomes that one would expect to observe in markets in which all demand response resources were able to participate on an equal footing with generation. As a result, adoption and implementation of the proposed rule could produce outcomes that are inconsistent with economic efficiency. Certain consumers would be paid subsidies for reducing their consumption that exceed the payments that are necessary to induce them to consume electricity in an efficient manner. The cost of these subsidies would, in all likelihood, be shouldered by other consumers, who would thereby be charged amounts that are unrelated to the cost of the electricity they consume or any other service that is rendered to them.

The proposed rule may be unsustainable in the long run and thus not achieve the NOPR's demand response objectives. The increase in costs resulting from the need to pay for these subsidies will encourage consumers to purchase their electricity outside of the RTO- and ISO-administered markets—exactly the

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[2] William W. Hogan, Providing Incentives for Efficient Demand Response ("October White Paper"), Oct. 29, 2009, at 4-6, contained in Motion for Leave to Answer and Answer of the Electric Power Supply Association and White Paper by Professor William W. Hogan, Docket No. EL09-68-000, Oct. 30, 2009.

opposite of the behavior that the proposed rule was intended to encourage.

Supporting Efficient Demand Response

In its Order No. 719, the Commission asserted, "Improving the competitiveness of organized wholesale markets is 'integral to the Commission fulfilling its statutory mandate to ensure supplies of electric energy at just, reasonable, and not unduly discriminatory or preferential rates.'"[3] In this, there is no dispute. But the NOPR goes on to assert, "[I]ncreasing the aggregate amount of demand response resources in the organized wholesale energy markets will help to move prices closer to the levels that would result if all demand could respond to the marginal cost of energy."[4] This statement is made without any caveats, as though it must hold, regardless of how the increased amount of demand response participation was obtained. In fact, whether this statement is true depends critically on what measures were undertaken to increase the aggregate amount of demand response resources.

If demand response resources are unable to bid into the markets at prices that reflect the value they place upon the electricity they actually consume, or if they do not have the proper incentives to do so, consumers may consume electricity even though the cost of producing that electricity exceeds its value to those con-

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[3] NOPR at P 2, quoting FERC Stats. & Regs. P 31,281 (2008) (Order No. 719) at P 1.

[4] NOPR at P 18.

sumers. Alternatively, consumers may fail to consume electricity even though that electricity could be produced at a cost that is less than the value it would have had for those consumers. Either of these is an inefficient outcome with associated costs imposed on the economy and individual consumers. In such cases, removing barriers to participation by these resources, and providing those resources with incentives to submit bids that reflect the value they place upon the electricity they consume, can increase efficiency, and can yield prices that are "closer to the levels that would result if all demand could respond to the marginal cost of energy."

But actions that do not provide the correct incentives for well-defined demand response products may yield inefficient outcomes, contrary to the Commission's expectations, even if those actions happen to increase demand response participation in electricity markets. And the Commission's proposed rule would not provide incentives for demand response providers to submit bids that reflect the value they place upon the electricity they consume. It is therefore unlikely that the proposed rule would meet the Commission's stated objectives.

This result would occur because the proposed rule is based on a misunderstanding of how to pay for the demand response that is offered into the market and the role that LMP plays in RTO- and ISO-administered markets. In the NOPR, the Commission states, "It is well-established practice in the organized wholesale energy markets to rely on LMPs to encourage efficient

behavior by market participants. The LMP represents the value of additional supply or reductions in consumption at each node within the RTO or ISO and, thus, reflects the marginal cost of the last unit necessary to efficiently balance supply and demand."[5]

But then the Commission goes on to claim:

> Given that the LMP represents the marginal value of the resource being used by the RTO or ISO to balance supply and demand, it follows that the LMP should be paid to any resource clearing in the RTO's or ISO's energy market. In balancing supply and demand, a one megawatt reduction in demand is equivalent to a one megawatt increase in energy for purposes of meeting load requirements and maintaining a reliable electric system. The ISO or RTO is able to avoid dispatching suppliers with higher bids, be they generation or demand response, by accepting a lower bid to either reduce consumption or increase generation.[6]

Consequently, the Commission has proposed a rule which would require "each Commission-approved ISO and RTO that has a tariff provision providing for participation of demand response resources in its energy market must pay demand response resources, in all hours, the market price for energy, i.e., full LMP, for demand reductions made in response to price signals."[7]

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[5] *Id.* at P 14 (footnote omitted).

[6] *Id.* at P 15.

[7] *Id.* at P 11.

While electricity markets differ in many important respects from markets for other goods, there are some similarities. For example, in the market for shoes, there is no need to pay consumers for reducing the number of shoes they purchase in order to ensure an efficient solution. Instead, the market is able to perform this function without regulatory intervention. If the price for a pair of shoes is less than the marginal value of those shoes to a consumer, that consumer buys them. If not, the consumer does not buy the shoes. The market clears at a price that sets supply equal to demand. The result is efficient because consumers who are willing to pay more than the market-clearing price for shoes pay that price, while consumers who are not willing to pay the market-clearing price do not pay that price. This latter group is better off because, by not buying the shoes, they avoid paying the price of the shoes, and the price of the shoes exceeds the value they would have realized if they had purchased those shoes.

Similarly, if we assume that all consumers could respond to the marginal cost of electricity, and we also assume that all consumers pay the LMP for the electricity they consume, then every consumer would have both the ability and the incentive to consume electricity whenever the marginal cost of producing that electricity is less than the marginal value of that electricity to it, and not to consume electricity whenever the marginal cost of producing that electricity is greater than the marginal value of that electricity to it—without the need to make separate payments to consumers to induce them to reduce their consumption.

The reason is that by not consuming electricity, the consumer avoids paying the LMP Not paying the LMP leaves the consumer better off than if he or she had paid the LMP and consumed the electricity. So charging consumers the LMP is all that is needed to induce efficient behavior, given these assumptions.

Of course, in reality, the assumptions made above do not hold. Not all consumers have the ability to respond to the marginal cost of electricity, and of those consumers with that ability, not all pay the LMP. Consequently, there is a role for programs that expand the ability for consumers to participate actively in the market by eliminating barriers to participation by demand response providers. There is also a role for programs that give consumers better incentives to submit bids that reflect the value they place upon electricity, and to consume when the price is less than that value, while not consuming when the price exceeds that value. But mandating that all RTOs and ISOs pay the LMP to *all* consumers *all* the time for *all* demand reduction will not bring about this outcome.

There are many circumstances where full LMP would be the appropriate price in different ways for different types of demand response. The two general cases involve consumers facing real-time prices and consumers that have explicit contracts purchasing a given quantity of electricity and then deciding not to use some or all of the contracted amount that would be resold in the market. For the first case, consumers facing real-time pricing are charged LMP for the amount they actually purchase, and no further pay-

ments are necessary. These consumers see the correct incentive because they save the LMP for anything they do not consume. For the second case, consumers purchase a fixed quantity and pay for it under some explicit arrangement such as a forward contract or a day-ahead purchase, and then in effect settle up for differences of actual consumption from the contract quantity at the applicable LMP These consumers see the correct incentive because they sell back at the LMP what they have purchased but not consumed.

However, the Commission proposal presumably would apply as well to a very different set of circumstances for consumers under full requirements tariffs at a fixed price but not for a fixed quantity. For these consumers, imputed demand response involves neither charging them LMP for what they consumed nor paying them LMP for the difference between what they purchased and what they consumed. For these consumers there would be a procedure for estimating the baseline of what they would have consumed, and then paying them for the difference between the actual consumption and the baseline amount. But these consumers have not actually purchased the baseline amount. It is for this form of imputed demand response that the Commission's policy would be problematic.

Paying the LMP to all consumers all of the time for imputed demand reduction will generally yield an inefficiently large amount of demand reduction paid for by those consumers who remain. This can be seen most easily in the case of consumers who pay the LMP

for the electricity they consume. If such a consumer does not consume electricity, under the proposed rule, not only would it not have to pay the LMP, but it would also be paid the LMP for electricity it does not consume. So, if we assume that the LMP is $40/MWh, the imputed demand response provider will have 2 × $40 = $80 more if it does not consume a MWh of electricity than if it consumes that MWh. In other words, the imputed demand response provider would be paid twice under the Commission's proposal.

The imputed demand response provider receives a double payment because it never purchased the electricity that the proposed rule would permit it to sell back to the RTO or ISO. As a result, under the proposed rule, it would receive the LMP for selling the imputed demand response, without having to pay for the right to consume that electricity in the first place. If it had paid for the baseline electricity, then paying the demand response provider the LMP for reductions in the amount of electricity it purchased would be entirely consistent with economic efficiency. But the proposed rule contains no such provisions. Most of the suggestions for implementing compensation in the case of imputed demand response can be seen as attempts to restore the equivalence with dynamic pricing or explicit contract purchases by charging for the imputed baseline purchases.

Unsurprisingly, this double payment can lead to inefficiently large amounts of imputed demand response, as demonstrated in an example in the October White Paper. In that example consumers at a given location

wished to consume as much as 70 MWh of electricity, and that they valued the first 50 MWh of potential consumption at $200/MWh, and the next 20 MWh at $70/MWh. If consumers were paid the LMP (as under the proposed rule), they would consume only 50 MWh of electricity, and the LMP would be set by the $40/MWh cost of the generator that would be running in that example. Consumers would only consume 50 MWh because if they consumed more, they would have to pay $40 for each MWh of additional consumption, and they would also forego a $40/MWh payment they receive for reducing their consumption. The overall net cost of additional consumption under the Commission's proposed rule is $80 per MWh consumed, which exceeds the $70/MWh value to consumers of the additional electricity. However, the cost of generating additional electricity, $40/MWh, is much less than the $70/MWh marginal value that consumers place upon additional consumption. Therefore, the Commission's rule leads to an inefficiently high amount of imputed demand response, because it dissuades consumers from consuming electricity even in cases where the cost of producing that electricity is less than the value of that electricity to consumers.

Instead, in order to promote market efficiency, demand response programs need to be targeted to situations where consumers may not have incentives to submit offers that reflect the value that they place upon the electricity they consume. Those programs should aim to modify those incentives so that such consumers have an incentive to act efficiently, instead of making payments indiscriminately to all consumers for reduc-

ing consumption while ignoring whether those consumers already have incentives to consume efficiently, and disregarding differences among consumers who do not have incentives to consume efficiently.[8]

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[8] As I noted in the October White Paper, some have argued that the LMP does not correctly reflect the cost of electricity, either because it does not fully incorporate the cost of environmental externalities, such as greenhouse gas emissions, or because it does not fully reflect the cost of shortages. These arguments should be addressed by other, broader-based measures that would ensure that generation and demand response compete on a level playing field. In contrast, procedures that are intended to supplement payments to demand response providers for these reasons without affecting payments to generation are likely to yield inefficient outcomes, because they discriminate against generation and in favor of demand response resources. *See* October White Paper at 7-9.

Additionally, as I also noted in the October White Paper, in certain circumstances, paying demand response providers more than the amount that is required to induce an efficient amount of demand response may be justified if the intent of such a program is to reduce the cost of providing demand response by spurring development of additional demand response resources. If it is unlikely that the developers of such demand response resources would be able to capture most of the benefits of their investments, underinvestment in demand response resources might result in the absence of such a payment. However, that argues for a limited, targeted program of payments to demand response providers—which might resemble many of the demand response programs currently implemented by RTOs and ISOs—and not the broad-based program that the proposed rule would mandate, which would make such payments to all demand response providers indefinitely. *See* October White Paper at 10-11.

How the Proposed Rule Would Affect Consumers

Aside from the impact on market efficiency, the proposed rule may also have significant and adverse effects on many consumers of electricity under various scenarios discussed below, which are discriminatory, and which simply may not be sustainable in the long term. To illustrate, consider another example in which we assume there are 1000 MW of price-insensitive load, so that the amount consumed will stay the same regardless of price. Since the load does not depend upon price, we do not have to worry about whether the imputed demand response program promotes more or less consumption than would be observed in a competitive, efficient market, because consumption is fixed. Also assume that there are more than 1000 MW of generation available to serve this load at a price of $50/MWh, and ignore transmission congestion, losses, minimum generation costs, and other complicating factors. Finally, assume that all consumers pay the LMP for all of the electricity they purchase from this RTO-administered market.

Before the introduction of any demand response program, the LMP is $50/MWh in this example, as that is the price where supply is equal to demand. Adoption and implementation of an imputed demand response program such as that contemplated by the proposed rule will not induce a reduction in consumption in this example, because the value that consumers place upon the electricity they consume is, by assumption, very large. Suppose, for purposes of this calculation, that value is $10,000/MWh. Then consumers are $10,000 –

$2 \times \$50 = \$9900$ better off if they consume electricity, pay the LMP for it (the first $50), and forego the $50 payment they would receive if they reduced consumption (the second $50) under the imputed demand response.

But simply because the consumers in this example plan to consume the same amount of electricity, no matter what the price, does not mean that they do not care what price they pay. Even if they do not plan to reduce their consumption in response to a demand response program, consumers still would like to minimize the net amount they pay for the electricity they consume. One way for at least some of them to do this is to move their consumption out of the RTO-administered market, thereby making it appear that they have reduced consumption. In reality, they have done no such thing, thus gaming the system.

Suppose in this example that a consumer with 100 MW of load is located next door to several 100 MW generators. An imputed demand response program such as that envisioned by the Commission gives the load and one of the generators an incentive to sign an agreement to take the generator "behind the meter," whereby that generator would provide electricity directly to serve the load.

In this case, the electricity would not flow into or out of the RTO-administered grid. Consequently, from the perspective of the RTO, there appears to have been a 100 MW reduction in load on the system, and an offsetting reduction of 100 MW in generation on the system. The supply and demand curves shift to the

left by an equal amount, so the LMP remains $50/MWh.

It is likely that this consumer will pay about $50/MWh to the generator for the electricity it consumes under this agreement. It will not pay significantly less than $50/MWh because the generator can sell the electricity it produces into the market for $50/MWh. And it will not pay significantly more than $50/MWh because the consumer can contract to purchase electricity from other generators at about $50/MWh. But under the imputed demand response program, the consumer will receive the $50 LMP for each MWh of electricity that it no longer purchases from the RTO-administered market, because it *appears* to have reduced its consumption. Since it no longer purchases any electricity in that market, the demand response payments will fully (or almost fully) offset the payments it must make under its contract with the generator, and it pays little or nothing for the electricity it consumes. Therefore, the only significant cost this consumer may incur is the cost associated with moving the generation behind the meter.

Such a program may be lauded as a "success" that has produced a 10 percent reduction in electricity consumption, but in fact it has merely moved the consumption somewhere where it is not visible to the RTO. The consumer continues to consume 100 MWh of electricity, just as before, which is not to say that the program has not had any effects. First, it has induced the consumer to spend money to move the generation behind the meter. From a social perspective,

this spending is wasteful, as it does nothing to promote increased efficiency. But it benefits this individual consumer, as it ensures that its consumption will no longer be visible to the RTO, making it eligible for imputed demand response payments.

In addition, this program affects other consumers. The payments made to imputed demand response providers under this program must be recouped somewhere. Presumably, they will be recouped from the load that continues to purchase electricity in the RTO-administered market. The RTO would pay \$50/MWh × 900 MWh = \$45,000 for electricity that generators sell into its market, and another \$50/MWh × 100 MWh = \$5,000 to the consumer who appears to have reduced consumption, even though that consumer has simply moved its consumption behind the meter. Therefore, the total amount paid by consumers buying from the RTO-administered market will be \$50,000, the same amount that was paid by consumers before 100 MW of generation and load moved behind the meter. But now 900 MW of load must cover all of the \$50,000 in costs, so those consumers will pay \$50,000 / 900 MWh = \$55.56/MWh to the RTO, instead of \$50/MWh, while the 100 MWh of load that moved its consumption out of the RTO-administered market pays little or nothing for its electricity.

Consumers who continue to purchase electricity from the RTO-administered market must pay not only the \$50/MWh value of electricity generated for their own use, but another \$5.56/MWh to cover the costs of the imputed demand response program (which are really

the value of electricity consumed by other consumers). There is no justification for this disparate treatment of otherwise identical consumers. This treatment is therefore discriminatory.[9] The outcome would be quite different under dynamic pricing or resale of electricity under an explicit contract, where LMP is appropriate and the cost shifting of imputed demand response does not arise.

Moreover, such an imputed demand response program may also contain the seeds of its own demise, as the increase in costs that the remaining loads must bear may induce others to leave the system as well. The increase in the price of electricity from $50/MWh to $55.56/MWh that results from the need to recoup these demand response payments from the remaining con-

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[9] Even if it were possible to recoup part of this cost from the 100 MW of unmetered load that is served by behind-the-meter generation, the charge would simply be reduced from $5.56/MWh to $5000 / 1000 MWh = $5/MWh. Consumers who purchase their electricity from the RTO-administered market would still have to pay $55/MWh, $50 to cover the cost of the electricity they consume, and $5 to cover the cost of the demand response program. The consumer whose load is served by behind-the-meter generation would pay a total of about $5/MWh consumed, as the amount it pays to the generator under the contract would be offset by the payments it receives from the demand response program. Therefore, other consumers would still bear most of the cost of the electricity consumed by the consumer served by behind-the-meter generation.

If the demand response program were structured so that all of its cost could be recouped from the entities who receive payments under the program, then the incentive for loads and generators to strike deals to take generation behind the meter would be eliminated.

sumers will give other consumers additional incentive to strike their own deals with generators to move behind their own meters. While the savings realized by those consumers as a result of such agreements might not have been large enough to justify the cost of moving those generators behind the meter when each MWh of electricity consumed cost $50, those savings might be high enough to justify other such investments if each MWh of electricity consumed costs $55.56.

If the increase in electricity prices were to induce consumers with another 300 MW of load to reach agreements with 300 MW of generation to move behind their meters, then a total of 600 MW of load would continue to be purchased in the RTO-administered market. The LMP would remain $50/MWh, since the demand and supply curves would each shift another 300 MW lower.

Now the RTO would pay $50/MWh × 600 MWh = $30,000 for electricity purchased from generation, and another $50/MWh × 400 MWh = $20,000 to the consumers who appear to have reduced consumption, even though those consumers have simply moved their consumption behind the meter. The total amount paid by consumers buying from the RTO-administered market would still be $50,000, the same amount that was paid by consumers before any generation or load moved behind the meter. But now 600 MW of load that remains in the RTO-administered market would have to cover all $50,000 in costs, so those consumers would have to pay $50,000 / 600 MWh = $83.33/MWh to the RTO, instead of $50/MWh. The 400 MW of

load that moved its consumption out of the RTO-administered market would continue to pay little or nothing, other than the cost of moving generation behind their meters.

Consumers who continue to purchase electricity from the RTO-administered market now would pay a $33.33/MWh surcharge to cover payments made to imputed demand response providers, in addition to the $50/MWh value of electricity generated for their own use. Again, this treatment is discriminatory, and there is no justification for this disparate treatment of otherwise identical consumers.[10]

The $83.33/MWh cost of electricity may induce yet more consumers to move generation behind their meters, leaving even fewer MWh of load to bear the $50,000 that the RTO must recoup from loads, and so on. The figure below illustrates the amount that the remaining consumers would need to pay to purchase

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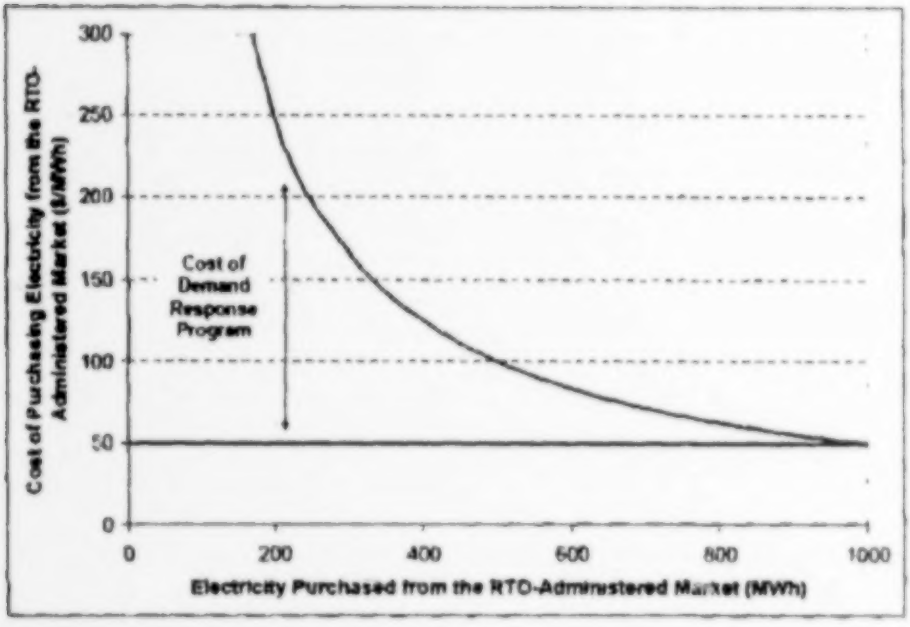
[10] In this case, if it were possible to recoup part of this cost from the 400 MW of unmetered load that is served by behind-the-meter generation, the charge would simply be reduced from $33.33/MWh to $20,000 / 1000 MWh = $20/MWh. Consumers who purchase their electricity from the RTO-administered market would still have to pay $70/MWh, $50 to cover the cost of the electricity they consume, and $20 to cover the cost of the demand response program. The consumers whose loads are served by behind-the-meter generation would pay a total of about $20/MWh consumed, as the amount they pay to the generators under the contracts would be offset by the payments they receive from the demand response program. Therefore, other consumers would still bear most of the cost of the electricity consumed by the consumers served by behind-the-meter generation.

their electricity from the RTO-administered market. As it shows, that amount grows at an increasing rate to the extent that the additional load deserts that market and contracts to be supplied with electricity provided by behind-the-meter generation, providing an accelerating incentive for even more consumers to desert the RTO-administered market.



However, there are likely to be many consumers who simply do not have the capability to enter into these behind-the-meter arrangements and would continue to purchase their electricity in the RTO-administered markets. This group of consumers, which is likely to include load-serving entities selling to a disproportionately large number of residential and small commercial consumers whose operations are not of sufficient size and scope to make it worth their while to incur the fixed costs associated with moving genera-

tion behind the meter, must pay not only for electricity generated for their own use, but also for electricity generated for consumption by other (generally larger) consumers for whom moving generation behind the meter is cost-effective, since consumers who move generation behind the meter will pay approximately zero for their electricity. (That is because the contract payments they make for electricity purchased from behind-the-meter generation should call for the consumer to pay approximately the LMP for electricity consumed, so the LMP payments made under the demand response program should roughly offset the cost of the contract payments, as shown above in the example.).

The situation could be worse than in these examples that assume the generation is efficient. For example, consumers who have inefficient backup generators would have an incentive to run such equipment to burn diesel oil or natural gas at much higher heat rates and substitute for measured electricity load. As long as the inefficient generator costs less than the LMP plus the retail rate, the imputed demand response program would create an incentive for these inefficient generators to run.

Note that in all these examples, the perverse incentives and unintended consequences do not arise for real-time pricing demand response and explicit contract demand response.

By adopting the proposed rule as applied to imputed demand response, and mandating that all RTOs pay the LMP to all consumers who reduce the amount of

electricity they purchase from RTO-administered markets, the Commission would be assuming that consumers would not respond to these incentives to move generators behind the meter or operate inefficient backup equipment. However, the Commission has not provided any evidence to support this assumption If the Commission's assumptions are incorrect, then the Commission-mandated imputed demand response programs could actually induce consumers and generators to stop participating in RTO-administered markets. This is not what this NOPR was intended to do. Instead, the NOPR asserted that facilitating participation by demand response resources would "help[] to increase competition in those markets."[11] By discouraging participation in RTO-administered markets, the imputed demand response programs that would be mandated by the proposed rule would likely increase costs due to the loss of efficiencies that are realized as a result of participation in a centrally dispatched LMP-based market (in addition to the fixed costs associated with moving generation behind the meter).

There is historical precedent for this result if the related market rules are not designed properly. In 1997, when PJM first began to operate its markets, the Commission mandated an approach to transmission pricing that gave market participants incentives to transact outside the PJM market. Under this approach, generators sold electricity at a hypothetical unconstrained price, and consumers purchased elec-

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[11] NOPR at P 3 (footnote omitted).

tricity at that price. Generators that were dispatched down due to transmission congestion were not compensated. However, those generators could evade these restrictions by self-scheduling transactions in which they would serve load. No congestion costs were charged in association with such transactions. As a result, generators that found themselves constrained from operating would self-schedule themselves to operate, which would cause other generators to be constrained off. Those generators then self-scheduled themselves as well. In the end, so many generators in PJM's western and central regions self-scheduled themselves that PJM found itself without any resources in those regions that it could dispatch downward, causing PJM to declare a minimum generation emergency (which permitted PJM to curtail transactions) on August 22, 1997, *during the system peak.*[12] Like the rule that the Commission mandated in 1997, the rule that the Commission proposes in this proceeding creates inconsistencies that gives market participants incentives to act outside the market. And, just as in 1997, if some market participants act on those incentives, that will create incentives for other market participants to act outside the market as well, creating the prospect that these incentives will snowball.

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[12] For another discussion of these events, see William W. Hogan, "Independent System Operator: Pricing and Flexibility in a Competitive Electricity Market," Feb. 1998, at 17-18, available at www.whogan.com.

The central failing of the congestion management procedure that the Commission directed PJM to apply in 1997 was that it did not charge market-clearing prices for access to transmission facilities when those facilities were congested. By making it cheaper for generators to gain access to those facilities by self-scheduling than by bidding into the market, the Commission made it impossible for PJM to use the market to allocate access to those facilities. Similarly, in this proceeding, by mandating subsidies that could make it cheaper for certain consumers to consume electricity if they purchase it outside the market than if they purchase it in the market, the Commission could make it impossible for RTOs and ISOs to operate their markets, if too many consumers elect to purchase their electricity outside those markets. The market rules in place in the RTO- and ISO-administered markets have, in general, been carefully crafted to give market participants incentives to act in a manner that is consistent with market efficiency. If the Commission now chooses to mandate procedures that are fundamentally inconsistent with market efficiency, the Commission runs the risk of undermining the operation of those markets in a manner reminiscent of 1997. The Commission should heed 1997's lesson and retract the proposed rule here in order to develop more tailored demand response requirements.

Price Reductions

An argument has been made that the inefficiencies and cost increases for remaining consumers could be justified or avoided by achieving price reductions in LMPs

that would reduce the total payments by consumers. For example, in the PJM proceeding, Allen Freifeld provided an affidavit for the Demand Response Providers asserting that the imputed demand response program would provide "a price mitigation service to all load in the region."[13] The implication is that this price mitigation would be a policy that the Commission should support.

This price reduction argument has a superficial appeal, but it is misdirected for at least two reasons. First, it is not likely to work. Second, even if it worked for a while it would be bad policy.

The price reduction argument misses the impact it would have on other aspects of the electricity market, most visibly in the case of organized RTO/ISO markets with explicit capacity requirements or markets. As is well known, the various market monitors have consistently reported that the energy and ancillary services payments have not been sufficient to support new investment in generating capacity. This has led to various policies, such as capacity markets, designed to provide direct or indirect payments to capacity (for both generation capacity and demand response capacity) that are intended to make up the missing money. Hence, the net effect of reducing average LMPs and payments in the energy market would be to increase payments through the capacity mechanisms. In prin-

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[13] Comments and Protest of Demand Response Supporters, Docket No. EL09-68-000, Sept. 16, 2009, Att. C (Affidavit of Allen M. Freifeld on Behalf of Demand Response Supporters) at 5.

ciple, these would be dollar for dollar, at least in the long run, and the putative reduction in payments by load would be an illusion. What would be real would be the spreading of capacity payments over different consumers and different hours that would mute rather than reinforce demand response incentives. As a result, it is more likely that real costs and total payments would go up, not down.

Even for cases where there is not an effective capacity market, or where the short run capacity payments are fixed and there is a temporary opportunity to suppress energy prices, this form of "benefit" would not be economically efficient and would not be an appropriate policy for the Commission. In effect, this price mitigation service is not a policy to move towards a more competitive and efficient market. Rather, it would be an application of regulatory authority to enforce a buyers' cartel. The price mitigation policy would not be improving efficiency. To the contrary, it would be employing government authority to transfer income from producers to consumers. Thus the pursuit of price mitigation of this type would run contrary to the Commission's policy of supporting and facilitating efficient, non-discriminatory electricity markets.

Efficient Demand Response Policy

The Commission's proposed rule does not distinguish between consumers who pay the LMP for the electricity they consume and consumers who pay fixed prices for their electricity, but this distinction is crucial. As I explained above, consumers paying the LMP already have incentives to consume electricity in a manner that

is consistent with economic efficiency. They do not need to be paid LMP, or any other amount, in order to provide them with such incentives. Therefore, demand response programs with added payments that are intended to encourage consumers to consume efficiently should not apply to them.[14]

On the other hand, consumers paying fixed prices for electricity generally do not have incentives to consume efficiently. A consumer who pays a fixed price to consume electricity that is less than the LMP at its location at a given time has less of an incentive to reduce its consumption of electricity than does a consumer that pays the LMP, since the consumer who pays the LMP will save more if it reduces consumption. Likewise, a consumer who pays a fixed price to consume electricity that is more than the LMP at its location at a given time has more of an incentive to reduce its consumption of electricity than does a consumer that pays the LMP, since the consumer who pays the LMP will save less by reducing its consumption. This is the reason why the proposed PJM demand response program, which was the focus of the October White Paper, differentiated between demand reduction provided by consumers who pay the LMP for the electricity they consume, and demand reduction provided by consumers who do not. Consumers who paid the LMP for the electricity they consumed were,

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[14] As discussed in footnote 8 above, it is possible that such consumers might be included in demand response programs whose intent is to reduce the cost of providing demand response by spurring development of additional demand response resources.

in most hours, ineligible for payments under that program.[15] Consumers who did not pay the LMP were eligible.

Consequently, if the Commission deems it necessary to mandate that RTOs and ISOs implement imputed demand response programs with certain standardized characteristics, any such programs should be limited to consumers who pay a fixed price for the electricity they consume that differs from the LMP, as it is only these consumers who may have inefficient incentives to consume electricity. Furthermore, the intent of any such programs should be to restore the incentives for economically efficient behavior that would exist if those consumers were paying LMP This would, in almost all circumstances, entail a payment to these consumers that is less than the payment of the full LMP that would be mandated by the proposed rule.

For example, suppose that in a given RTO-administered market, the LMP at a given location and time is $60/MWh, and there are three consumers at that location, each of which can reduce its consumption in response to price signals. Consumer A pays the LMP for the electricity it consumes, Consumer B pays $50/MWh for the electricity it consumes, and Consumer C pays $40/MWh for the electricity it consumes. The payments that should be made to each of these consumers to ensure they have incentives to act in an

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[15] PJM did propose to make payments to consumers who pay the LMP during the nine percent of hours with the highest LMPs. I recommended against this aspect of PJM's proposed demand response program. *See* October White Paper at 18-19.

economically efficient manner differ because these consumers' circumstances differ.

- Consumer A should not receive any payments for demand reduction. It already has an incentive not to consume electricity if the value it places upon consuming that electricity is less than the $60/MWh marginal cost of consuming electricity.
- Consumer B should receive a payment of $10/MWh for demand reduction. It pays $50 for each MWh of electricity it consumes, so if it is paid $10 whenever it reduces its consumption of electricity by 1 MWh, the total financial impact of consuming an additional MWh would be the $50 it must pay for the electricity it consumes plus the $10 payment it would forego as a result of not having reduced its consumption, for a total of $60. Therefore it would have an incentive to consume electricity if it values that consumption at more than $60/MWh, and it would not have an incentive to consume electricity if it values that consumption at less than $60/MWh. These are the same incentives that apply to Consumer A, and they are consistent with economic efficiency.
- Consumer C should receive a payment of $20/MWh for demand reduction, in which case the total financial impact of consuming an additional MWh would be the $40 it must pay for the electricity it consumes plus the $20 payment it would forego as a result of not having reduced its consumption, which once again totals $60. Therefore, Consumer C, like Consumers A and

> B, also would have an incentive to consume electricity if it values that consumption at more than $60/MWh, and would not have an incentive to consume electricity if it values that consumption at less than $60/MWh.

By contrast, the Commission's proposed rule would require that each of these consumers receive a $60/MWh payment for imputed demand reduction. In each case, such a payment may induce the consumer to reduce its consumption of electricity by a larger amount than is economically justified. Inefficiency would result, because it would be possible to provide these consumers with additional electricity at a cost that is less than the value they place upon that electricity, but those consumers would choose not to consume that electricity so as not to forego the demand response payments.

In fact, the only circumstance in which an imputed demand response payment of LMP is economically justified is when the fixed price that a consumer pays is zero. In such cases, paying consumers the LMP for imputed demand reduction would give them the same incentives to consume that apply to consumers who pay the LMP for the electricity they consume. However, the number of consumers who pay a fixed price of zero for the electricity they consume is likely to be very small.

Implementation

Implementing appropriate compensation for demand response would be simple in the case of consumers

with real-time pricing or an explicit contract for a fixed quantity. In these cases consumers would be charged at the applicable LMP for what they consume or paid the applicable LMP for the amount purchased through the contract and sold back as demand response.

In the case of imputed demand response, payment for the difference between the actual consumption and the baseline could take several forms. All the various options have the feature of adopting a net payment which would emulate the net payment under an explicit contract for a fixed quantity. Doing this through the price for imputed demand response would fall under the type of LMP for the demand reduction minus some proxy for the purchase of the baseline (at price G) for a net payment of LMP-G. The details would depend in part on the form of the consumer tariff, but the general structure would be the same.

An alternative to using the implicit demand response price would be to create an effective purchase and sale of the imputed demand response amount. The October White Paper contained a mechanism for implementing such an imputed demand response program.[16] Briefly, each imputed demand response transaction would be unbundled into an electricity purchase and an electricity sale. The estimated amount of demand reduction that has been provided would still be equal to the difference between baseline and actual consumption. This quantity difference would be deemed to have been purchased by the consumer under what-

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[16] October White Paper at 19-21.

ever arrangements the consumer purchases from the system. It would be added to the metered electricity purchases of the consumer or its load-serving entity. Separately, the same quantity would be sold to the RTO or ISO by the consumer at the LMP, as with any other spot market electricity sale, and as envisioned under the proposed rule.

A consumer who pays a fixed price for electricity would pay that fixed price for the right to consume its baseline level of consumption. It would also receive the LMP for any reductions in consumption relative to that baseline. Consequently, it would realize the difference between the LMP and the fixed price for the electricity that it was entitled to consume at the fixed price, but which it did not consume. Such a program would provide the same incentives for efficiency as the demand response program with an explicit contract. It would provide those incentives by recognizing that the consumer could purchase electricity at a price that differs from the LMP, thereby giving that consumer an incentive to consume an inefficient amount of electricity, but it also provides those incentives by ensuring that imputed demand response providers are not able to sell something they did not buy. The very essence of imputed demand response programs is that but for the actions of the consumer, electricity would have been purchased and consumed. It is this deemed electricity purchase that is presumably being sold to the system operator. The separation of the transaction into a purchase and a sale clarifies the underlying economics and makes it clear that in order to provide incentives for an economically ef-

ficient amount of demand response, imputed demand response providers must be charged for the electricity they would have consumed, in addition to being paid the LMP for not actually consuming that electricity.

This unbundling approach has a number of attractive features. It avoids the necessity for the RTO/ISO to estimate "G," the proxy for the purchase which the MISO calls the Marginal Foregone Retail Rate (MFRR), that could be different for different consumers at the same location. It raises no new jurisdictional issues as the transaction could be structured through the wholesale purchases of the load serving entity and essentially the same way as forward contracts to purchase more than actually consumption are settled at the LMP. And it would provide incentives for the local jurisdictional entities and regulators to allocate the costs to the ultimate imputed demand response provider to avoid cost shifting and preserve efficient incentives.

Conclusion

The NOPR is based on the premise that it is necessary to pay demand response providers the LMP for all demand reductions in order to place generation and demand response on a level playing field, but this premise is mistaken. Instead, to create a level playing field, it is only necessary to make demand response payments to consumers who do not pay the LMP for the electricity they consume, and who as a result may not have incentives to consume efficiently without such payments, and even those payments should, in almost all circumstances, be less than the LMP. Because the

demand response programs that the proposed rule would mandate would make payments to some demand response providers when such payments are unnecessary to induce efficient behavior, and would make payments to other demand response providers that exceed what is needed to induce efficient behavior, they would not "move prices closer to the levels that would result if all demand could respond to the marginal cost of energy,"[17] as the Commission intends. Instead, the proposed rule would encourage inefficiently large amounts of imputed demand response. The cost of payments made to participants in these demand response programs would be borne by consumers who are unable to participate in these programs. Consequently, these consumers would be asked to pay not only the cost of purchasing electricity for their own use, but also payments made to other consumers, which could induce those consumers to engage in strategies to move their consumption out of RTO- or ISO-administered markets, thereby creating the illusion of a reduction in consumption. These costs would be likely to fall disproportionately on smaller consumers. Moreover, the demand response programs that the proposed rule would mandate may simply be unsustainable, in that they may provide incentives for enough consumers to transact outside the RTO- and ISO-administered markets that the costs for the remaining consumers become untenable. Instead, the Commission should focus upon compatible demand response programs, which would address

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[17] NOPR at P 18.

those specific circumstances when consumers in a given organized market do not have an incentive to act efficiently, and which would provide incentives in those circumstances that are appropriate given the incentives for inefficient behavior that apply to each consumer.

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[i] William W. Hogan is the Raymond Plank Professor of Global Energy Policy, John F. Kennedy School of Government, Harvard University and a Director of LECG, LLC. This paper was prepared at the request of the Electric Power Supply Association. This paper draws on work for the Harvard Electricity Policy Group and the Harvard-Japan Project on Energy and the Environment. The author is or has been a consultant on electric market reform and transmission issues for Allegheny Electric Global Market, American Electric Power, American National Power, Aquila, Australian Gas Light Company, Avista Energy, Barclays, Brazil Power Exchange Administrator (ASMAE), British National Grid Company, California Independent Energy Producers Association, California Independent System Operator, Calpine Corporation, Canadian Imperial Bank of Commerce, Centerpoint Energy, Central Maine Power Company, Chubu Electric Power Company, Citigroup, Comision Reguladora De Energia (CRE, Mexico), Commonwealth Edison Company, COMPETE Coalition, Conectiv, Constellation Power Source, Coral Power, Credit First Suisse Boston, DC Energy, Detroit Edison Company, Deutsche Bank, Duquesne Light Company, Dynegy, Edison Electric Institute, Edison Mission Energy, Electricity Corporation of New Zealand, Electric Power Supply Association, El Paso Electric, GPU Inc. (and the Supporting Companies of PJM), Exelon, GPU PowerNet Pty Ltd., GWF Energy, Independent Energy Producers Assn, ISO New England, Luz del Sur, Maine Public Advocate, Maine Public Utilities Commission, Merrill Lynch, Midwest ISO, Mirant Corporation, JP Morgan, Morgan Stanley Capital Group, National Independent Energy Producers, New England Power Company, New York Independent System Operator, New York Power Pool, New York Utilities Collaborative, Niagara Mohawk Corporation, NRG Energy, Inc., Ontario IMO, Pepco, Pinpoint Power, PJM Office of Interconnection, PPL Corpora-

tion, Public Service Electric & Gas Company, Public Service New Mexico, PSEG Companies, Reliant Energy, Rhode Island Public Utilities Commission, San Diego Gas & Electric Corporation, Sempra Energy, SPP, Texas Genco, Texas Utilities Co, Tokyo Electric Power Company, Toronto Dominion Bank, Transalta, TransCanada, TransÉnergie, Transpower of New Zealand, Tucson Electric Power, Westbrook Power, Western Power Trading Forum, Williams Energy Group, and Wisconsin Electric Power Company. Michael Cadwalader provided assistance in preparation of this paper. The views presented here are not necessarily attributable to any of those mentioned, and any remaining errors are solely the responsibility of the author. (Related papers can be found on the web at www.whogan.com).

STATE OF NEW YORK DEPARTMENT OF PUBLIC SERVICE

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[PICTURE OMITTED]

PUBLIC SERVICE COMMISSION

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May 13, 2010

SENT VIA ELECTRONIC FILING
Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Room 1-A209
Washington, D.C. 20426

Re: Docket No. RMI0-17-000-Demand Response Compensation in Organized Wholesale Energy Markets; and, EL09-68-000 -PJM Interconnection, L.L.C.

Dear Secretary Bose:

For filing, please find the Notice of Intervention and Comments of the New York State Public Service

Commission in the above-entitled proceeding. Should you have any questions, please feel free to contact me at (518) 474-1585.

Very truly yours,

/s/ ALAN T. MICHAELS
ALAN T. MICHAELS
Assistant Counsel

Attachment

UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. RM10-17-000

DEMAND RESPONSE COMPENSATION IN ORGANIZED WHOLESALE ENERGY MARKETS

Docket No. EL09-68-000

PJM INTERCONNECTION, L.L.C.

NOTICE OF INTERVENTION AND COMMENTS OF THE NEW YORK STATE PUBLIC SERVICE COMMISSION

NOTICE OF INTERVENTION

On March 18, 2010, the Federal Energy Regulatory Commission (FERC or Commission) issued a Notice of Proposed Rulemaking (NOPR) in which it proposed compensation for demand response resources participating in organized wholesale energy markets. The New York State Public Service Commission (NYPSC) hereby submits its Notice of Intervention and Comments in the above-captioned proceeding pursuant to the Notice published in the Federal Register on March 29, 2010, and Rule 214 of the Commission's Rules of Practice and Procedure.

Copies of all correspondence and pleadings should be addressed to:

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BACKGROUND

On March 18, 2010 the Commission issued a NOPR which proposed an approach for compensating demand response resources participating in organized energy markets.[1] FERC states its goal is to "improve the competitiveness of organized wholesale energy markets and thus ensure just and reasonable rates."[2]

The Commission states that over the past several decades, it has acted to expand wholesale energy markets and support competitive markets.[3] In Order No. 719, FERC determined that "active participation by customers in organized wholesale energy markets through demand reductions helps to increase competi-

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[1] Docket No. RM10-17-000, Demand Response Compensation in Organized Wholesale Energy Markets, 130 FERC ¶ 61,213 (issued March 18, 2010), hereinafter referred to as the "NOPR"

[2] NOPR at Summary para.

[3] *Id.* at para. 2.

tion in those markets."[4] FERC also found that demand reductions can occur generally in two ways: (1) response of customers to dynamic rates; and, (2) demand response that acts as a resource.[5] Within the NOPR, the Commission demonstrates its support for compensation for demand response acting as a resource and requests comments from stakeholders.

INTRODUCTION

Within the NOPR, the Commission states that demand response helps to improve the functioning and competitiveness of energy markets by lowering prices, mitigating generator market power, and has the potential to support system reliability.[6] The Commission then requests comment on eight specific questions relating to its proposal for demand response compensation.[7] Each will be reviewed in turn.

DISCUSSION

The NYPSC supports demand response (DR) as a method of achieving greater competitiveness in wholesale markets. However, the methodology for demand response compensation must be considered in the context of the existing retail market structures to determine the best implementation approach. As discussed below, we recognize that paying the consumer Locational Marginal Price (LMP) for demand response

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[4] *Id.* at para. 3.

[5] *Id.*

[6] NOPR at para 4.

[7] *See*, NOPR at para. 20, 21, and 22.

compensation provides value to the customer of LMP plus the avoided retail rate (if the customer is billed at LMP by its retail service provider, the value "paid" would be 2 times LMP). However, we believe LMP plus the retail rate remains the best approach for New York, given the circumstances of our wholesale and retail markets. This payment approach will provide a strong initial incentive for fledgling DR programs, recognize the cost of externalities, reflect the beneficial effect of DR on market power mitigation, and maintain simplicity. An LMP-based DR program should be reviewed within five years (or sooner, as circumstances require) to determine its effect on the market, and whether there exists a continued need.

It should first be noted that the New York wholesale market has an ISO-based demand response program as proposed by the NOPR. Since 2001, the New York wholesale market has had a demand response program based on day ahead energy prices (the Day Ahead Demand Response Program or DADRP). The current program uses LMP as the compensation method, and has a minimum bid threshold of $75/MWh. The enrollment in the program has remained small compared to the New York Independent System Operator's (NYISO's) capacity and emergency based DR programs.[8]

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[8] According to the Report of the NYISO to the FERC Re: Annual Report in Docket Nos. ER01-3001 and ER03-647 on the NYISO's Demand Side Management programs, dated January 15, 2010, 22 customers were enrolled in the DADRP in 2009.

From a theoretical perspective, an Independent System Operator's/Regional Transmission Organization's (ISO/RTO's) demand response program at the wholesale level is a substitute for retail dynamic rates that signal to customers the value of the product purchased. In many cases, retail prices do not signal to customers the hourly marginal cost of electricity, but instead signal a monthly average price. This means that for peak hours, the retail price for non-LMP-billed customers is below the wholesale hourly price, and consumers consume more than the efficient amount due to the inappropriate price signal.

Demand response programs offered by an ISO/RTO augment the retail price signal by paying customers not to consume electricity. There are two different approaches that may be used to compensate consumers who participate in an ISO/RTO DR program. To obtain an efficient economic value signal of the electricity, i.e. one in which price equals marginal cost, the formula for DR compensation should be the LMP minus the retail rate. This formula yields a net price signal that equals the wholesale LMP ([(LMP Retail Rate) + Retail Rate = LMP]). Alternatively, the ISO/RTO DR incentive may be set at LMP. Using the latter formula, the customer receives a price signal of the retail rate plus LMP

While the NYPSC acknowledges the overstated price signal inherent in an LMP-based formula for DR compensation, NYPSC, on balance, favors the proposal to use the LMP-based formula for demand response compensation presented within the NOPR for the near

term. The NYPSC recognizes the benefit of the objectives sought by FERC, and agrees that demand response compensation is a vehicle to achieve these goals. Although, we understand that an LMP demand response compensation formula may result in uneconomic demand response decisions in the markets (i.e., a price signal that exceeds marginal cost), it also creates an incentive to participate in DR programs, helps to account for the cost of externalities, and is relatively simple to apply. Further, while high signals may exist within the LMP proposal, we have seen little interest from market participants under the New York ISO's LMP-based payment approach. Changing the compensation approach to anything less than what is presently offered by the NYISO will only create a lesser incentive for participants. Accordingly, implementing the LMP-based compensation discussed in the NOPR is supported, subject to the caveat that demand response program compensation be revisited.

DR programs created as a result of this NOPR should be reviewed within five years, or sooner, if warranted. The purpose of the review should be to determine the market responses to the DR compensation. Further, real time pricing at the retail level may increase, making DR compensation at the wholesale level as a resource unnecessary.[9]

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[9] For customers already receiving hourly pricing, the demand for DR program payments should be reviewed much earlier. As noted previously, when customers are subject to hourly pricing in their retail rates, the overpayment provided in an LMP-based DR compensation approach at the wholesale level is the most severe.

In order to focus responses and to promote a thorough review of the topic, the Commission provided questions on the subject of demand response, and requested comments to each, which are provided below.

1. **Is there a need to compensate demand response acting as a resource in organized wholesale energy markets?**[10]

The NYPSC supports the Commission's proposal to compensate demand response. In instances where the retail rate does not provide a signal of the marginal cost of electricity as determined by the wholesale market, DR should provide that signal to customers. Demand response programs without adequate incentives for customers to reduce their energy usage are likely to fail. To attract ratepayers to actively participate in wholesale markets, incentives must offset the cost of altering regular daily habits and activities. The NYISO currently has a demand response program which has LMP-based compensation, and yet despite the tariff, the program is barely utilized by customers. Any approach that provides an incentive less than an LMP-based compensation would achieve even fewer results. To procure demand response, LMP compensation for DR appears to be warranted.

Therefore, the application of the ISO-based demand response program to hourly retail pricing customers should be reviewed at least within two years to assess the effectiveness of the DR program and the continued need for compensation exceeding LMP.

[10] NOPR at para.20.

2. What alternative approaches to compensating demand response are viable compared to the approach recommended by FERC?[11]

The NYPSC is aware of two prominent alternative approaches, both of which deduct retail prices from LMP to compensate demand response. The first would have the ISO/RTO charge the Load Serving Entity of the DR provider for the MWh of DR provided. The LSE would in turn charge the DR provider the retail rate for the DR MWh provided. This approach would have the effect of subtracting the retail rate from the DR provider's DR compensation. The net effect is a price that equals LMP.

A second approach is to use a proxy retail rate to subtract from the LMP incentive. The first approach suffers from a potential to be unduly confusing for the end user charged for MWh that were not used. The second approach suffers from the administrative burden of tracking retail rates for multiple utilities, ESCOs and power authorities. These approaches would create undue confusion for retail customers and administrative difficulties for state commissions and ISOs/RTOs.

The NYPSC recommends maintaining programs using LMP-based compensation and revisiting the market response in five years, or earlier, as required. The compensation must create an incentive for customers to enroll in the program and curtail their energy usage. In New York, despite using LMP as a

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[11] *Id.*

compensation formula in the DADRP, and providing assistance for installing meters or technology, customers are not participating in the demand response program to any significant degree. Anything less than LMP-based compensation would only provide a lower incentive for customers to participate.

The Commission also asked whether reduction in consumption is comparable to increase in electricity production. The two market changes are comparable, but demand response may be preferable to supply stimulation due to the externalities that are not included in price of generation. For example, the addition of generation creates non-internalized air pollution costs and associated facilities' environmental costs (e.g. transmission lines), which are not fully included in generator rates. Therefore, the Commission should err, if at all, by over-stimulating demand response resources in the short term, and revisiting and reevaluating the market's response in five years, or sooner, if as warranted.

3. **Is paying LMP to demand response resources comparable to compensation paid for generation in ISO/RTO markets?**[12]

Paying LMP for demand response may be considered comparable to the compensation paid to the generators. NYPSC also notes the significant administrative difficulties that would be created by adopting a formula for demand response compensation

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[12] *Id.*

which begins with LMP and reduces it by a number of other factors, often customer specific. The market mechanisms are already complicated and we do not believe the public would be well served by adopting a complex compensation calculation that could vary by customer.

4. Should payment of LMP apply to all hours?[13]

The payment of LMP should not apply to all hours. Currently the DADRP program has a minimum bid threshold of $75/MWh. This static threshold limited participation in the program in 2009 because prices did not get above the threshold on a consistent basis. A bid threshold is needed to limit free riders, customers who had intended to reduce electric consumption for reasons other than market prices and seek DR compensation for their actions. The New England Independent System Operator's DR program has a dynamic threshold based on fuel prices and heat rates of marginal generation. This solution addresses the issue of a static threshold and limits free riders, and would be supported by NYPSC.

5. Should FERC require payment of LMP across all ISO/RTOs, or do the differences among ISO/RTOs justify varying levels of demand response resource compensation?[14]

After an initial five year period of LMP compensation, the Commission should defer to each ISO/RTO to

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[13] *Id.*

[14] NOPR at para 20.

determine its needs for demand response resource compensation. As retail dynamic rates are implemented throughout ISO/RTO territories there may be less need for ISO-based DR programs. As the effectiveness of demand response compensation programs are based upon the markets, both wholesale and retail, each ISO/RTO may have different compensation levels required to stimulate active participation depending on the characteristics of their markets.

6. Should the Commission allow regional variations for ISO/RTO that does not seek to compensate demand response?[15]

The Commission should allow regional variation in compensation for DR. Each ISO/RTO is different and may have different needs that DR can address. Some regions may be able to address the need for DR through retail rates, and thus not need to continue a largely redundant wholesale DR program.

The New York wholesale market is unique in that it has a retail market where a significant amount of load is subject to dynamic rates. The NYPSC has worked to expand dynamic retail pricing for the state's largest commercial and industrial (C&I) customers.[16] C&I customers were put on default day ahead retail hourly

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[15] *Id.*

[16] See, Case 03-E-064I,Order Denying Petitions for Rehearing and Clarification in Part and Adopting Mandatory Hourly Pricing Requirements (MHP Order) (issued April 24, 2006), which expanded or implemented hourly pricing for all New York's major utilities.

pricing. Customers are free to seek other types of commodity rate structures from energy service companies (ESCOs), but if they remain with the utility, they are billed for commodity based on the day ahead hourly price. While the ESCO can bill customers on any rate structure they choose, the ESCO is responsible for buying their customer's actual hourly load from the wholesale market and should have an incentive to help customers flatten their load shape in order to reduce their energy cost. The load that is subject to hourly retail pricing far exceeds the amount of load participating in the DADRP program.[17] The Commission has stated that retail-level price responsive demand is not the subject of this proceeding;[18] the retail pricing situation, however, must be examined in order to determine if it will affect decisions about the proper design of wholesale market programs and incentives.

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[17] In 2009, the NYISO's DADRP had approximately 22 customers and 331 MW of load participating in the program, while approximately 625 customers totaling 1,128 MW of load were on retail day ahead hourly pricing (3.7% of load) and additional 2,248 customers totaling 4,533 MW (14.7% of load) on retail ESCO rates that could be dynamic also (totaling 18.3% of load). The NYPSC continues to expand the number of customers that are subject to retail mandatory hourly pricing.

[18] NOPR at FN 4.

7. **Should the Commission conduct periodic reviews of demand response compensation?**[19]

Once established, there is no need for the Commission to review the demand response of each ISO/RTO. It should be the responsibility of each ISO/RTO to administer and periodically review the demand response program within its market.

8. **Are the terms "expected levels," "price signals," and "market prices" sufficiently defined?**[20]

The terms noted above are understood by the stakeholders; there is no need to define them additionally.

CONCLUSION

NYPSC recognizes that demand response compensation is a beneficial stimulant to obtain the goals established by FERC in the NOPR. Specifically, NYPSC agrees that demand response can improve competition, mitigate generator market power, and support system reliability.

NYPSC supports paying LMP for demand response even though, by producing a price signal of "LMP + retail rate", it overstates marginal cost. While this overstated price signal could be argued to produce inefficiently large demand reductions, we support it for three main reasons. First, an addition to LMP is needed to signal environmental externalities, and to

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[19] *Id.* at para. 21.

[20] *Id.*

reflect the beneficial effect of DR on market power mitigation. Second, proposals to net-out the retail rate can be either legally questionable, administratively difficult, or both. Third, the current NYISO DR program, despite its use of an LMP compensation approach, has yielded only a very small amount of demand response after eight years of experience. Any DR compensation structure that is less than LMP will fail to create the incentive required to stimulate active participation in demand response.

Finally, NYPSC respectfully suggests that each ISO/RTO revisit demand response compensation after five years, or sooner, should circumstances require. As each ISO/RTO is unique, each can determine its own needs or adjustments to demand response compensation. The application of the ISO-based demand response program to hourly pricing customers should be reviewed at least within two years to assess the effectiveness of the DR program and the continued need for compensation exceeding LMP.

Respectfully submitted,

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Dated: May 13, 2010
Albany, New York

UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. RM10-17-000

DEMAND RESPONSE COMPENSATION IN ORGANIZED
WHOLESALE ENERGY MARKETS

May 13, 2010

COMMENTS OF THE PUBLIC UTILITIES COMMISSION OF OHIO

I. Background

On March 18, 2010, the Federal Energy Regulatory Commission (Commission) issued a Notice of Proposed Rulemaking in the above captioned docket. The proposed rule would establish a uniform approach for compensating demand response resources in RTO energy markets with the objectives of improving the competitiveness of organized wholesale energy markets and ensuring just and reasonable rates. The Commission's proposal is that RTOs with tariff provisions providing for the participation of demand response resources in day-ahead and real-time energy markets "must pay demand response resources, in all hours, the market price for en-

ergy, i.e. full LMP, for demand reductions made in response to price signals."[1]

II. Comments

The Public Utilities Commission of Ohio (PUCO) is offering the following comments and joining in the Comments of the Organization of Midwest ISO States.

A. Role of Demand Response in Energy Markets

Demand that responds to changes in energy market prices is an essential characteristic of an efficient and competitive power market. The PUCO recognizes that such demand response can provide significant economic and reliability benefits. Demand response can reduce market prices and ultimately prices to consumers, particularly when the slope of the supply curve is steep or resources are in short supply.[2] Active demand participation in energy markets can help mitigate market power. Additionally, the inclusion of demand response in the market will tend to reduce volatility and spread risks

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[1] Notice of Proposed Rulemaking, 130 FERC ¶ 61,213 at P 11 (footnote omitted).

[2] However, the price mitigation impacts of short-term demand response in energy markets may be, in part, offset by the operation of capacity markets which impose forward purchase requirements that would not otherwise be selected by consumers. In PJM's RPM market, capacity prices reflect the net cost of new entry after deducting energy market revenues. Lower energy market prices will tend to increase the net cost of entry and thus capacity market prices. For this and other reasons, existing capacity markets can represent a barrier to the development of price responsive demand and efficient markets.

when compared to markets without demand response. Demand that responds to price changes in real time also offers significant reliability benefits. When a generator trips off or power flow is curtailed, the initial impact is to increase real-time LMPs where power supplies are reduced. Price responsive demand and demand response resources participating in the real-time energy market will respond to such price changes by reducing energy consumption. This creates a beneficial feedback mechanism, minimizing operational risks, the need to rely on reserves, and the redispatch of generation which might otherwise be required. From an operational perspective, this beneficial feedback mechanism also will tend to increase the predictability of power flows. The development of price responsive demand and demand resources that participate in real-time energy markets also could play a key role in integrating into the grid significantly more variable renewable resources. It is well established that a large portion of the potential benefits of competitive power markets are associated with the development of demand response.[3] Many of these benefits will accrue not only to those who reduce their demand, but also other consumers and suppliers in the affected markets. The question facing the Commission is not whether

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[3] *Wholesale Competition in Regions with Organized Electric Markets*, Order 719, 73 Fed. Reg. 64,100 (October 28, 2008), FERC Stats. & Regs. P 31,281 (2008); FERC Staff Report. 2007. "Assessment of Demand Response & Advanced Metering," Docket No. AD06-2-000, September. FERC Staff Report. 2006. "Assessment of Demand Response & Advanced Metering," Docket No. AD06-2-000, August.

to support the emergence of greater demand response in energy markets, but how to most effectively and efficiently encourage its development.

B. Compensation of Demand Response Resources in Wholesale Energy Markets

The Commission is seeking comment on "approaches to compensating demand response resources in organized wholesale energy markets."[4] The PUCO believes that demand response resources should be fairly compensated and that there should be efficient incentives for the development of such resources. While the Ohio Commission has not specifically opposed RTO economic demand response programs that provided limited additional and temporary incentives to initiate development of demand response, the most appropriate payment for demand response resources in wholesale energy markets is LMP minus the generation portion of the retail rate. This is the economically efficient incentive for demand response resources in these markets. By reducing demand, the responding consumer is already avoiding payment for energy that was not consumed. A basis for recognizing demand response resources in the wholesale market arises only where retail energy prices do not reflect prices in wholesale markets. Retail energy markets, the setting of retail rates, and retail rate designs are and should remain subject to state jurisdiction. A consumer who avoids paying the generation portion of its retail rate and

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[4] Notice of Proposed Rulemaking, 130 FERC ¶ 61,213 at P 20.

is compensated in the wholesale market for any difference by which the wholesale price exceeds the generation portion of the consumer's retail rate will achieve the same economic outcome as if the customer had offered an equivalent supply resource into the energy market. To ensure consistency with applicable retail rates, the retail rate deduction (or the calculation of the deduction) should be established in advance of the wholesale transaction, if practicable, and should be submitted to the state retail rate authority for validation.[5] The Organization of Midwest ISO States and other parties have filed comments that are consistent with the position of the Ohio Commission and presented detailed analyses that support paying demand response resources LMP minus a deduction based on the customer's retail rate.[6]

C. Impacts on the Development of Demand Response

The Commission's consideration of appropriate steps to facilitate the development of demand response should not end with its decision in this proceeding. The Ohio Commission is concerned that an over emphasis on

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[5] Comments of the Illinois Commerce Commission at p. 11. Ohio is a retail access state in which it is possible to separate the generation portion of the retail rate from non-generation related components of the rate. However, given differences among the states and the potential complexity of and interactions between elements included in some retail rates, RTOs should submit the calculation of the retail rate deduction to the appropriate state regulatory commission for validation.

[6] See: Notice of Intervention and Comments of the Organization of MISO States; Comments of the Illinois Commerce Commission.

providing incentives for demand response resources in wholesale energy markets could divert attention from and potentially retard the development of more efficient approaches. We believe that a primary focus should be on directly addressing barriers to demand participation, including existing RTO tariffs that require load serving entities to carry capacity for demand that would not be present at higher energy prices.

Ohio is among the states pursuing investments in advanced metering infrastructure and retail dynamic pricing. Ohio's electricity statute specifically encourages the development of advanced metering infrastructure and time-differentiated pricing.[7] As price responsive demand and related smart grid initiatives are implemented, electricity markets can become more efficient and increasingly resemble competitive markets in other sectors of the economy where consumers naturally and seamlessly respond to changing prices. This will represent a change in focus from RTO demand response programs, which implicitly treat demand response as the resale of energy back into to the wholesale market, to energy markets with sloping demand curves that reflect the price and consumption preferences of millions of individual consumers.[8] Utility interruptible tariffs and direct load

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[7] Section 4928.02(D), Ohio Revised Code.

[8] The development of appropriate forms of time differentiated and dynamic retail pricing for residential consumers offers an opportunity to significantly expand the potential of demand response. Federal Energy Regulatory Commission Staff. 2009. "A National Assessment of Demand Response Potential," June.

control programs have provided and continue to provide a first generation of demand response. RTO programs can be considered second generation approach. Price responsive demand, where consumers simply see and respond to dynamic retail prices, represents a more transparent and efficient third generation of demand response. It avoids the need for RTOs to estimate baseline consumption and pay for reductions from what it is assumed that consumers would have otherwise utilized. The Commission should avoid retarding the development of this third generation of demand response.

We recognize and appreciate the on-going stakeholder discussions in the RTOs to accomplish the coordination between wholesale and retail markets and wholesale market reforms necessary for the development of price responsive demand. We encourage the Commission's continued focus on removing barriers to price responsive demand.

The outcome of this proceeding, however, cannot be entirely separated from the ability of the states to make the needed investments and pursue price responsive demand at the retail level. To the extent uneconomic incentives for demand response resources in wholesale markets result in a significant uplift in RTO prices, states and utilities will have fewer resources with which to make the necessary investments in metering and enabling technologies. The Commission should proceed cautiously to ensure that additional incentives for wholesale market demand response resources in the short-term do not have the unintended consequence of retarding the longer

term development of retail demand response and coordinated retail and wholesale markets.

D. Conclusion

The Ohio Commission recognizes the importance of demand response to the achievement of efficient, reliable, and competitive power markets. And, we support fair compensation for demand response resources in wholesale energy markets. However, the Commission's proposal that RTOs pay demand response resources full LMP takes the incentives for wholesale demand response resources a step too far. It would provide an incentive to the supplier of a demand response resource that exceeds the payments available to an equivalent supply resource. The Commission should instead focus on removing the existing barriers in wholesale markets toward the development of retail price responsive demand and proceed cautiously when considering potentially uneconomic payments that could result in uplift in RTO prices. For these reasons, the Ohio Commission opposes adoption of the proposed rule.

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[LOGO OMITTED]

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May 13, 2010

VIA ELECTRONIC FILING

Ms. Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
Office of the Secretary
888 First Street, N.E.
Washington, D.C. 20426

RE: Demand Response Compensation in Organized Wholesale Markets, Docket No. RM10-17-000

Dear Ms. Bose:

Enclosed please find for electronic filing the comments of Verso Paper Corp. in support of the Notice of Proposed Rulemaking in the above captioned proceeding.

Thank you for your attention to this matter.

Regards,

/s/

Glenn S. Poole
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Manufacturing Support Manager-Energy
207-469-1230
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UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. RM10-17-000

DEMAND RESPONSE COMPENSATION IN ORGANIZED WHOLESALE ENERGY MARKETS

COMMENTS OF VERSO PAPER CORP. IN SUPPORT OF THE NOTICE OF PROPOSED RULEMAKING

Verso Paper Corp. ("Verso") submits these comments in support of the March 18, 2010, Notice of Proposed Rulemaking ("NOPR") issued in the above captioned docket.[1]

I. OVERVIEW OF VERSO PAPER CORP.

Verso is in the paper business.[2] Based in Memphis, Tennessee, Verso is a leading North American producer of coated papers, including coated groundwood and coated freesheet, as well as supercalendered and specialty paper products.[3] Verso has four mills,

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[1] Verso is a member of the Consumer Demand Response Initiative ("CDRI") and supports their filed comments.

[2] *See* www.versopaper.com.

[3] The competition in the paper business is global. *The State of Wisconsin's Paper Industry*, February 2003, prepared by the Wisconsin Paper Council, at page 9-10 ("[t]o a large extent the paper industry has shifted from a regionally-based industry to a

two of which—the Androscoggin mill and the Bucksport mill (collectively the "Verso mills" or "mills") are located in Maine[4]—and thus within the footprint of the Independent System Operator of New England ("ISO-NE"). The Verso mills employ approximately 1,500 people in rural Maine.

Verso approaches the NOPR from the multiple perspectives of an electricity generator, a large user of electricity, as well as a significant demand response provider. The Verso mills are generators, with approximately 500 MW of on-site generation that meet mill requirements and make sales of energy and capacity into the ISO-NE market.[5] As such, Verso can understand generators' concerns that improved demand response in organized markets will reduce the need to call into service higher priced marginal units, thereby lowering locational marginal prices ("LMPs") and thus the revenues that generators, including the Verso mills, receive from the market.

At the same time, Verso consumes a significant amount of electricity in making paper and would benefit from the lower LMPs that would result from the greater use of demand response in organized wholesale markets. Paper production is one of the most en-

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globally-based industry;" "imports captured 90% of the increased U.S. demand between 1997 and 2000").

[4] Verso's remaining two mills are located in Sartell, Minnesota, and Quinnesec, Michigan. Currently neither of these mills sells energy or capacity into organized electric markets.

[5] The majority of this generation is either from natural gas, hydroelectric or biomass, *i.e.*, the by-product of making paper.

ergy intensive manufacturing industries—and costs have increased.[6] According to a U.S. Department of Commerce Report, "[f]rom 2000 to 2005, the cost of fuels and purchased electricity for the pulp and paper industry increased from $6.9 billion to $8.8 billion, a 26% increase."[7]

Verso recently teamed with the U.S. Department of Energy in making a voluntary commitment to reduce its energy intensity by 25% over the next 10 years, a team effort consistent with Verso's energy strategy to reduce its costs and environmental footprint and with U.S. energy policy to reduce energy use and the overall cost of energy use, including environmental impacts. In announcing the program, Verso's President and Chief Executive Officer Mike Jackson said:

> The Save Energy Now program fits well with Verso's energy strategy, which is to reduce energy consumption overall, generate more green energy from

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[6] *Energy Policy and U.S. Industry Competitiveness*, Rachel Halpern, Sarah Lopp, Samuel Beatty and others, U.S. Department of Commerce, International Trade Administration, Office of Energy and Environmental Industries at page 7, July 2007 ("Department of Commerce Report").

[7] *Id.* The Department of Commerce Report attributed the closing of 232 paper mills and the loss of 182,000 jobs (12% of the employment in the paper industry) since 2000 to rising energy costs.

renewable biomass, and reduce our carbon footprint while simultaneously reducing costs.[8]

II. VERSO SUPPORTS THE NOPR AND URGES EXPEDITIOUS ACTION.

A. Providers of Demand Response Incur Costs and Perform in Organized Markets as Well as or Better than Generators and thus Should be Paid the Same Price as Generators, *i.e.* the LMP.

Because demand response providers provide the same or better service than traditional generators and incur costs when they provide that service, they should be paid the same price as generators, *i.e.* the LMP, when they participate in the organized wholesale market. First, demand response providers arguably provide better service in meeting load than traditional generators. For example, the Verso mills can quickly respond in meeting system requirements, reducing over 60 MW of load in as little as 10 minutes. Moreover, the Verso mills are capable of providing this service 24 hours a day, 365 days a year. Finally, they can provide this service without having to construct major new facilities—the Verso mills are integrated to the grid, available to provide service, and indeed they have provided that service for the last several years.

As an example, on August 2, 2006, ISO-NE reached its record peak load of 28,130 MW. On that day, the Bucksport mill provided over 60 MW of demand re-

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[8] *See, Verso Among Elite Group to Sign Save Energy Now Leader Pledge*, included as Attachment A. *See also*, Attachment B, *DOE Launches Save Energy Now LEADER Program.*

sponse—almost 10% of the 625 MW of demand reduced[9]—enabling ISO-NE to shave its system-wide peak during this critical supply period.[10]

Second, the Verso mills incur costs in providing demand response, the same as traditional generators that produce electricity. Demand response providers that reduce their use of electricity incur costs, both in terms of risks and lost opportunities, as well as direct labor costs, in shutting off equipment.

As to the risk, reducing over 60 MW of load in as little as 10 minutes requires that the Verso mills shut down paper and pulp machines that are conservatively worth in excess $200 million. These are extremely complex machines with hundreds of pieces of rotating equipment, and when you turn off these machines, you must do so carefully, lest they be damaged. Moreover, there is a risk that the machines may not restart

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[9] *ISO New England Responses to Questions for Panelists, Technical Conference on Demand Response in Wholesale Markets* (Docket No. AD07-11) April 23, 2007 at 1. ("ISO-NE Response") The ISO-NE would add that "[e]fficient markets need active demand participation," *i.e.*, "competitive markets offer efficient prices if: supply is competitive and demand is active." *ISO-NE Response* at 2.

[10] Stephen Whitley, Senior Vice President and Chief Operating Officer, ISO New England Inc., *Remarks at the Federal Energy Regulatory Commission Technical Conference on Demand Resources in Wholesale Markets (Docket No. AD07-11) Panel on Demand Response as an Alternative or Complement to Transmission Expansion*, April 23, 2007 at 1. ("*Whitley Remarks*"). Mr. Whitley added that demand response did an "outstanding job" in meeting system need on August 2, 2006. *Whitley Remarks* at 2.

quickly or properly, resulting in significant repair costs and lost production.

In addition, there are risks in participating in the demand response program, *i.e.*, the penalties incurred for not meeting demand response commitments. Demand response providers commit to certain demand response levels. ISO-NE audits those commitments. During an ISO-NE audit, ISO-NE will call a demand response provider, such as the Verso mills, to reduce load by the amount of its commitments. To the extent that the demand response provider cannot reduce its load (for example, the Verso mills may not be operating due to problems at the mills or with the local utility or as a result of a lightning strike), the ISO-NE substantially penalizes the demand response provider until the next audit, generally six months away.[11]

There are also significant opportunity costs that result from Verso's participation in the demand response program, specifically the lost opportunities to produce paper. When Verso shuts down paper and pulp machines to provide demand response, those machines are not available to make paper, but Verso

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[11] In contrast, in organized electric markets, traditional generation can, in general, avoid the imposition of penalties for nonperformance by simply informing the Independent System Operator, in advance, that the unit is on an outage. *See e.g.*, *California Independent System Operator Corporation*, 107 FERC ¶ 61,329 at P 16 (2004)(stating that Scheduling Coordinators can avoid Uninstructed Deviation Penalties for failure to meet its hour-ahead schedule due to a real-time outage if it notifies the CAISO of an outage within 30 minutes of the onset of the outage.)

nonetheless still incurs costs associated with its paper-making business, such as salaries that must be paid and debt that must be serviced, without the revenues from the sale of paper that it would have produced from the idle machines.

Finally, reducing over 60 MW of load in as little as 10 minutes of time involves more than flicking a switch —direct labor costs are incurred. Given the risk of damaging the equipment, careful planning must take place and manpower brought to bear to implement the plan. For example, implementing the plan at the Verso mills requires extensive coordination among personnel in various departments, spread out over some 50 acres at each mill.

The Commission allows generators to reflect direct labor costs, as well as risk premiums[12] and opportunity costs,[13] in their bids, and if bids reflecting those costs set the market clearing price, then all market participants receive that price. Given that demand response providers incur costs similar to generators' costs, and provide the same or better service than generators, they, too, should receive the market clearing price, *i.e.*, the LMP, when they provide demand response.

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[12] *Southwest Power Pool, Inc.*, 117 FERC ¶ 61,110 at P 27 (2006) ("[I]ncluding an appropriate risk premium may be part of the just and reasonable rate.").

[13] *PJM Interconnection, L.L.C.*, 130 FERC ¶ 61,230 at PP 21-23 (2010) (finding that tariff must include specific provisions that provide for systematic inclusion of opportunity costs in the bids of energy and environmentally limited resources).

B. Expeditiously Adopting the Final Rule would be Consistent with U.S. Energy Policy.

Adopting the final rule will facilitate the greater use of demand response in wholesale markets by ensuring that demand response providers are adequately compensated for the service provided and the costs incurred. Greater demand response in wholesale markets would be consistent with U.S. energy policy to use less energy, reduce the overall cost of electricity, including environmental costs, and increase the reliance on renewable energy. As such, expeditiously adopting the final rule would be consistent with U.S. energy policy.

As participation in demand response increases in wholesale markets, the amount of generation needed to serve load will be reduced. The generation reduced will often be technology from the 1960s and 1970s. Such technology is less efficient than more modern technology and when this technology is used, additional costs are incurred by the market and society as a whole. This less efficient technology has a higher heat rate and thus uses more energy to produce the same amount of electricity. In addition, it costs more to operate thereby raising LMPs (and the costs that consumers ultimately pay). Finally, because such technology has environmental capabilities that are less likely to be consistent with current objectives, it adversely impacts the environment.

In addition, the greater use of demand response fits well with the policy of using more renewable energy, such as wind or solar. For example, a synergy exists

among demand response, renewable energy, and energy storage. Investments in renewables (such as wind energy) can be paired with systems that allow charging of storage devices at night (when the wind blows the hardest and electricity demand is low). The storage device then can discharge its stored electricity during peak periods. Demand response complements intermittent renewable generation and energy storage devices by filling in the gaps in renewable generation or energy storage devices.

This relationship between renewables and demand response is best exemplified by the so-called "Texas wind event" of February 26, 2008. On that date, a 1,400 MW reduction in wind production occurred in ten minutes. At the same time, colder weather increased demand by over 4,400 MW (and lower than scheduled production from other supplies of electricity compounded the problem). The Electric Reliability Council of Texas avoided widespread outages by implementing its demand response program, appropriately titled Loads Acting as Resource (LAARs). Under that program approximately 1,100 MW of demand response from large industrial and commercial users (like the Verso mills) responded within 10 minutes.[14] As the American Wind Energy Association recognized in analyzing the event, demand response is a "proven tool" to maintain grid reliability (and avoid involuntary outages) in the face of signifi-

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[14] *ERCOT Demand Response Program Helps Restore Frequency Following Tuesday Evening Grid Event*, ERCOT Press Release, February 27, 2008, included as Attachment C.

cant variations of load and the sudden loss of generation.[15]

C. The Commission Should Move Forward Expeditiously with the NOPR, Notwithstanding Arguments to the Contrary.

As set forth above, the NOPR is sound and consistent with U.S. energy policy. Apparently, however, it will not be universally supported.

For example, a leading economist in the electricity field, Dr. William W. Hogan,[16] has argued against the Commission's proposal.[17] His arguments however,

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[15] *Why the Texas Reliability Event on February 26, 2008 Raises No Concerns About Much Higher Wind Penetration*, American Association of Wind Energy, included as Attachment D.

[16] *Providing Incentives for Efficient Demand Response*, William W. Hogan, Mossavar-Rahmani Center for Business and Government, John F. Kennedy School of Government, Harvard University, Prepared for the Electric Power Supply Association, Docket No. EL09-68-000, October 29, 2009 ("*Hogan Paper*").

[17] Dr. Charles Cicchetti discusses the overlapping responsibilities and potential jurisdictional conflict between the states and FERC in implementing demand response. *Comments of Charles J. Cicchetti, Ph.D.*, filed April 27, 2010 in Docket No. RM10-17-000 at 10 ("[t]his is a federal NOPR. However the state PUCs would still need to set the "just and reasonable" tariffs for the NWHs that demand-side aggregators would produce at retail on customers' premises and then package to be sold into organized wholesale markets. This initial step that causes NWHs to be produced is largely a state PUC domain.").

Any potential conflicts between the states and FERC are by no means insurmountable. There are a variety of vehicles to address these conflicts, not the least being the Commission's recently pro-

are no basis for the Commission not to move forward expeditiously.

Dr. Hogan argues that demand response providers would be overcompensated if paid the LMP without an offset for the savings in electricity not consumed, and suggests some sort of subsidy is at play.[18] As set forth above, however, the Verso mills incur costs to provide demand response, similar to generators that incur costs to generate electricity, and thus paying demand response providers the same price as a generator is no more a subsidy than the price paid the generator.

In any event, Dr. Hogan's argument starts from an incorrect premise, *i.e.*, in today's market-based electric market, the revenues recovered from the market should only reflect the direct cost to provide service such as labor, fuel, and return on capital, *etc.* To the contrary, in today's market-based pricing scheme, the "costs"[19] to provide the service have long been "di-

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posed national action plan that would assist in facilitating the coordination between the states and the federal government on demand side issues. *The Federal Energy Regulatory Commission Staff, Draft for Comment of the National Action Plan on Demand Response*, Docket No. AD09-10 (Mar. 11, 2010).

[18] *Hogan Paper* at 10 (Criticizing the argument that "subsidizing these resources now will promote their development, thereby driving down the cost of developing additional resources, which would eliminate the need to subsidize them in the future. This is closely related to the learning-by-doing that may create an externality not incorporated into market prices.").

[19] *PJM Interconnection, LLC*, Docket Nos. EL03-236-004, EL03-236-005, EL03-236-006 and EL04-121-000, 112 FERC ¶ 61,031 at P

vorced" from the "revenues" that are obtained from the market, for even generators themselves.[20]

Market participants bid into the market based on factors other than their direct costs to provide the service. For example, generators can bid their opportunity costs and a premium to compensate for risk —both also costs that Verso incurs to provide demand response services—as well as scarcity pricing. If those bids set the market clearing price, then all generators receive that price, regardless of their individual "costs" to generate.

Moreover, while Dr. Hogan appears to recognize that the LMP is appropriate given the benefits that

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87 (2005) ("This is not to say that accounting measures of out-of-pocket costs truly reflect all marginal costs for each unit. Opportunity costs for example are marginal costs that may not always be reflected in accounting costs. The opportunity costs of units with limited operating hours high lighted by Mirant and EPSA are representative of these non-accounting costs.").

[20] The most extreme example, of course, is the whole concept of a single price auction. A nuclear generator with a marginal cost of virtually zero receives the LMP even if the LMP is set by a natural gas fired generator with a heat rate of 12,000 BTU. When that occurs, the Commission does not find that the nuclear generator is over-recovering its costs. *Commonwealth Edison Co. and Exelon Generation Co.*, 113 FERC ¶ 61,278 at P 43 (2005)) (Further, with regard to the AG's concerns that . . . all winning bidders would be paid a uniform price regardless of their actual cost of supplying electricity and that the clearing price would be set by the highest-cost winning bidder in the auction, this pricing methodology is known as the "single clearing price" method and has the benefit of encouraging all sellers to place bids that reflect their actual marginal opportunity costs.).

demand response provides society, such as environmental benefits, in general he expresses concern that generators may not be compensated in the same fashion.[21] As to his specific point about compensation for environmental benefits, in New England, the prices paid both (i) recover "out-of-pocket" environmental costs and (ii) compensate generators for being cleaner burning.

The Regional Greenhouse Gas Initiative ("RGGI") program is an example. Fossil fueled generation, such as natural gas fired generation, must purchase RGGI allowances consistent with their CO2 emissions. The cost of such allowances (a marginal cost of operation) can be included in their bids. Stated another way, their bids are higher than they would have been absent purchasing the RGGI allowances. If the natural gas fired generator is called, the price paid will recover the costs of allowances.

At the same time, generators are compensated for being cleaner burning. A non-fossil fueled generator (e.g., wind, hydro, nuclear) will be compensated for being cleaner burning because the LMP price they receive will reflect the higher bids of the fossil gener-

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[21] *Hogan Paper* at 7 ("In short, programs that reward demand respond providers for their impact on environmental externalities, without providing similar rewards to generators with similar impacts, fail to provide a level playing field"); *id.* at 9 ("If demand response providers are rewarded for contributions to reliability that are not included in the LMPs, but generators that provide electricity at those times do not receive such rewards, that is not a level playing field.").

ators purchasing the allowances. Similarly the natural gas fired generator will be compensated when less "cleaner burning" generation, for instance a coal fired generator that spends more on the additional allowances required, clears the market.

As to Dr. Hogan's general point, as a generator Verso recognizes that the hybrid mix of competition and regulation in electric markets has long caused (and will continue to cause) difficulties in pricing electric products. In the meantime, however, the Commission has found that the LMP is the correct price in organized markets.[22] The rules proposed in the NOPR correctly recognize that, to the extent that a demand response provider assists in meeting wholesale load, it should be paid the market clearing price, *i.e.*, the full LMP, the same as any other market participant.

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[22] California Independent System Operator Corp., 116 FERC ¶ 61,274 at P 10 (2006) ("Under locational marginal pricing, or LMP, prices in wholesale markets vary by location and time, based on the true physical limitations of the transmission grid, and reflect the incremental cost of meeting customer demand at each location. Locational marginal pricing will communicate the true market value of electricity at each location, as well as the cost of alleviating congestion between any two locations. This will create financial incentives to dispatch the lowest cost energy, when considering all transmission bottlenecks. In the long-term, by making energy and congestion prices more transparent, locational marginal pricing will help encourage transmission and generation investment at appropriate locations, as well as demand response.").

III. CONCLUSION

WHEREFORE, for the reasons set forth above, Verso Paper Corp. supports the rules proposed herein and urges expeditious Commission action.

Respectfully Submitted,

* * * * *

ATTACHMENT A

[LOGO OMITTED]

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NEWS RELEASE

FOR IMMEDIATE RELEASE

Verso Among Elite Group to Sign *Save Energy Now* Leader Pledge

MEMPHIS, Tenn., December 3, 2009—Verso Paper Corp. (NYSE: VRS) announced today its participation in the Department of Energy's (DOE) *Save Energy Now* Leader program in which the Company has pledged to reduce energy intensity by 25% over the next ten years. Verso representatives, President and Chief Executive Officer, Mike Jackson, and Director of Energy Technology, Mark Daniel, officially signed the pledge at a ceremony hosted by Assistant Secretary of Energy Cathy Zoi at the Capitol Visitor Center in Washington, DC on December 2, 2009.

"The *Save Energy Now* program fits well with Verso's energy strategy, which is to reduce energy consump-

tion overall, generate more green energy from renewable biomass, and reduce our carbon footprint, while simultaneously reducing cost," said Verso's President and Chief Executive Officer, Mike Jackson. This partnership pledge offers Verso an opportunity to utilize the expertise of the DOE staff and our engineers to implement the projects necessary to achieve the Company's energy efficiency goals."

The DOE established the *Save Energy Now* Leader initiative to partner with industry and contribute to the American Recovery and Reinvestment Act goals through industrial energy intensity and carbon reductions. Through partnerships with states, local entities, utilities, associations and end-users, industry can leverage resources to increase energy efficiency and save energy and money. Presiding over the signing ceremony was the DOE's Industrial Technology Program Manager, Douglas Kaempf, who recognized the participating companies as having "distinguished themselves as energy-management champions among their industry peers."

In addition to the *Save Energy Now* program, Verso has been actively working with the DOE on a variety of energy initiatives. In October of this year, Verso received a $9.3 million grant award from DOE, which was equally matched by the Company, to install 12 energy projects in three of Verso's four mills. These projects are shovel ready and are designed to reduce the thermal energy needed in the pulp and papermaking process to produce Verso's coated paper products.

About Verso

Based in Memphis, Tennessee, Verso Paper Corp. is a leading North American producer of coated papers, including coated groundwood and coated freesheet, and supercalendered and specialty products. Verso's paper products are used primarily in media and marketing applications, including magazines, catalogs, and commercial printing applications such as high-end advertising brochures, annual reports, and direct-mail advertising. Additional information about Verso is available on the Company's Web site at www.versopaper.com. References to "Verso" or the "Company" mean Verso Paper Corp. and its consolidated subsidiaries unless otherwise expressly noted.

Forward-Looking Statements

In this press release all statements that are not purely historical facts are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements may be identified by the words "believe," "expect," "anticipate," "project," "plan," "estimate," "intend," and similar expressions. Forward-looking statements are based on currently available business, economic, financial and other information and reflect management's current beliefs, expectations and views with respect to future developments and their potential effects on Verso. Actual results could vary materially depending on risks and uncertainties that may affect Verso and its business. For a discussion of such risks and uncertainties, please refer to Verso's filings with the Securi-

ties and Exchange Commission. Verso assumes no obligation to update any forward-looking statement made in this press release to reflect subsequent events or circumstances or actual outcomes.

###

ATTACHMENT B

[SEAL OMITTED]

News Media Contact(s): **For Immediate Release**
(202) 586-4940 December 2, 2009

DOE Launches Save Energy Now LEADER Program

32 Companies Sign Pledge to Reduce Energy Intensity by 25 Percent

WASHINGTON, DC Energy Secretary Steven Chu announced today the launch of the Save Energy Now® LEADER Program, which will provide technical assistance and resources to companies that pledge significant improvements in industrial energy efficiency. At an event this afternoon, 32 companies representing a broad spectrum of the U.S. industrial sector will join with DOE Assistant Secretary for Energy Efficiency and Renewable Energy Cathy Zoi to sign a voluntary pledge to reduce their industrial energy intensity by 25 percent over the next decade.

"These companies' commitments to energy efficiency not only generate significant energy and carbon savings, but also show the entire business community the profitable steps that can be taken to move us all toward a clean energy future," said Secretary Chu. "Working together with American manufacturers, we will leverage the potential of energy efficiency to create new jobs, make our economy more competitive, and reduce carbon pollution."

The U.S. industrial sector accounts for more than 18 million jobs in the United States, as well as nearly 30 percent of the energy used nationwide and 27 percent of the country's carbon emissions. The Obama Ad-

ministration has made major commitments to improving energy efficiency as a path toward enhancing our energy security and strengthening the American economy, including more than $250 million in Recovery Act investments to improve the efficiency of the industrial and information technology sectors.

The LEADER program is a new component of the existing and successful Save Energy Now initiative through which companies partner with DOE to conduct energy audits and assessments designed to identify the opportunities for energy and cost savings in the companies' operations. Participating businesses also have access to tools and training to implement recommendations designed to help reduce their energy use and lower operating costs. Over 2,000 plants received energy assessments through Save Energy Now from 2006 to 2009. To date, those assessments have identified opportunities for $1.3 billion in identified cost savings, 119 trillion Btu of natural gas savings, and 11.2 million metric tons of CO2 savings.

The 32 LEADER Companies marked their commitment to the 25 percent energy intensity reduction goal by signing a voluntary pledge at the event. These charter member companies agreed to establish energy use and energy intensity baselines, and develop an energy management plan over the next 12 months. As indicated by the special "LEADER" designation, these companies are more than just first actors on the path to greater energy efficiency; they are coming forward to serve as actual role models and pace setters on an ongoing basis for others in the industrial sector. In

return, the companies will receive access to select DOE resources, as well as national recognition for energy management achievements.

The companies signing the pledge today include:

- 3M (St. Paul, MN)
- AT&T (Dallas, TX)
- BPM, Inc. (Peshtigo, WI)
- Bridgestone (McMinnville, TN)
- Briggs & Stratton (Wauwatosa, WI)
- Cummins, Inc. (Columbus, IN)
- Danfoss (Baltimore, MD)
- Didion Milling (Johnson Creek, WI)
- The Dow Chemical Company (Midland, MI)
- Flambeau River Papers (Park Falls, WI)
- Honeywell (Morristown, NJ)
- Ingersoll Rand/Trane (Piscataway, NJ)
- Intel (Santa Clara, CA)
- JR Simplot (Boise, ID)
- Manitowoc Grey Iron Foundry (Manitowoc, WI)
- Mohawk Industries (Dalton, GA)
- Neenah Foundry (Neenah, WI)
- Nissan North America (Smyrna, TN)
- Osram Sylvania (Danvers, MA)
- Owens Coming (Toledo, OH)
- PPG Industries (Pittsburgh, PA)
- Quad/Graphics, Inc. (Sussex, WI)
- Schneider Electric (Palatine, IL)
- Serious Materials (Sunnyvale, CA)
- Shaw Industries (Dalton, GA)
- Sherwin-Williams, Richmond (Richmond, KY)
- Spirax Sarco, Inc. (Blythewood, SC)

- Thilmany Papers (Kaukauna, WI)
- ThyssenKrupp Waupaca (Waupaca, WI)
- United Technologies Corp. (Hartford, CT)
- Verso Paper (Memphis, TN)
- Volvo Trucks, Inc. (Dublin, VA)

U.S. Department of Energy, Office of Public Affairs, Washington, D.C.

ATTACHMENT C

[LOGO OMITTED]

PRESS RELEASE
February 27, 2008

ERCOT Demand Response Program Helps Restore Frequency Following Tuesday Evening Grid Event

The Electric Reliability Council of Texas (ERCOT) implemented the second stage of its emergency grid procedures Tuesday evening following a sudden drop in the system frequency.

Preliminary reports indicate the frequency decline was caused by a combination of events including a drop in wind energy production at the same time the evening electricity load was increasing, accompanied by multiple power providers falling below their scheduled energy production. In addition, the drop in wind energy led to some system constraints in moving power from the generation in the north zone to load in the west zone, resulting in limitations of balancing energy availability. The wind production dropped from over 1700 megawatts (MW) three hours before the event, down to 300 MW at the point the emergency procedures were activated.

By moving directly to the second stage of the emergency procedures, the system operators were able to activate ERCOT's demand response program known as Loads Acting as Resource (LAARs), which added approximately 1,100 megawatts pf resources within a 10-minute period. LAARs are typically large industrial and commercial users who are paid to curtail their electricity use as needed for reliable grid operation.

Most of the interruptible loads were restored after approximately an hour and a half.

Other than the interruptible loads, no other customers in the ERCOT region lost power due to the event.

The emergency procedures were declared at 6:41 pm and ended at 9:40 pm.

ERCOT operations will be preparing a more detailed and quantitative report on this event in the next few weeks.

ADDITIONAL BACKGROUND

Emergency Electric Curtailment Plan (EECP)

Alert (pre-EECP)—When reserves fall below 2500 MW, ERCOT Operations will:

- Start Reliability-Must-Run units
- Instruct generation owners to suspend testing
- Deploy non-spin reserves
- Dispatch quick-start capacity

EECP Step 1—When reserves fall below 2300 MW, ERCOT Operations will:

- Instruct all available generation to come online
- Secure emergency power from neighboring electrical grids through direct-current ties

EECP Step 2—When reserves fall below 1750 MW, ERCOT Operations will:

- Drop customers who have been paid to accept the risk of interruption (known as "Load acting as a Resource," or LaaR)
- Transfer load to neighboring grids through block-load transfers
- Issue a media appeal, if not already done, asking the public for voluntary energy conservation

ECP Step 3—When reserves continue trending downward or if needed to maintain system frequency at 60 Hertz (Hz), ERCOT Operations will:

- Drop additional interruptible loads (known as "Emergency Interruptible Load"), if available

ECP Step 4—To maintain system frequency at 59.8 Hz or greater, ERCOT Operations will:

- Instruct local utilities to implement rotating outages to reduce load

The Electric Reliability Council of Texas (ERCOT) manages the flow of electric power to 21 million Texas customers representing 85 percent of the state's electric load and 75 percent of the Texas land area. As the independent system operator for the region, ERCOT schedules power on an electric grid that connects 38,000 miles of transmission lines and more than 550 generation units. ERCOT also manages financial settlement for the competitive wholesale bulk-power market and administers customer switching for 6 mil-

lion Texans in competitive choice areas. ERCOT is a membership-based 501(c)(4) nonprofit corporation, governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT's members include consumers, cooperatives, independent generators, independent power marketers, retail electric providers, investor-owned electric utilities (transmission and distribution providers), and municipal-owned electric utilities.

CONTACT

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ATTACHMENT D

[LOGO OMITTED]

WHY THE TEXAS RELIABILITY EVENT ON FEBRUARY 26, 2008 RAISES NO CONCERNS ABOUT MUCH HIGHER WIND PENETRATION

On February 26, 2008, a drop in frequency on Texas's transmission grid caused the Electric Reliability Council of Texas (ERCOT) to put in place an Emergency Electric Curtailment Plan. The event was reported in some media outlets as having been caused by a sudden drop in output from wind projects. In fact, as the information below makes clear, other factors had a greater impact in this particular incident. Over the 40-minute period preceding the start of load curtailment, wind generation declined by 80 MW relative to its schedule, non-wind generation decreased by 350 MW relative to its schedule, and load rapidly increased to a level that was 1,185 MW more than forecast. More generally, disturbances of this type routinely involve conventional power plants. The incident in reality shows that the key to successful electric system management lies in a diverse power supply, of which wind can reliably be a large part. AWEA (the American Wind Energy Association) has pulled together the following background information and highlights from the report issued by ERCOT on the event. This provides both perspective on the event and insights into the issues going forward.

ERCOT's full report is available at:

http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/27706_114_577769.PDF

Complex electric systems are comprised of many dynamic parts, including power plants, fuel supplies, power delivery infrastructure, and aggregate levels of consumption. Maintaining the reliability of an electric system requires robust operating procedures to handle contingencies, including multiple simultaneous events. As this report establishes, ERCOT has such procedures in place and they work. Yet, particularly as regional fuel sources and power options are diversified, there are improvements to grid operating procedures that can and should be made. As an action item in response to this event, ERCOT has determined to incorporate wind forecasting into short term planning to better inform its capacity procurement needs. The wind industry supports and applauds that conclusion, as it will enable continued diversification of power supplies while maintaining the robustness and reliability of the grid. As a GE study commissioned by ERCOT recently reported, with the use of wind forecasting wind energy deployment in Texas can be more than tripled to at least 15,000 MW without negative consequences for system reliability.

GE's study is available at:

http://www.ercot.com/meetings/ros/keydocs/2007/1022/Variability_and_Predictability_draft_dlvd_2a.zip

Some observations regarding the February 26, 2008 ERCOT event:

1. **The drop in frequency was successfully managed and no customers involuntarily lost power. The event was the result of several factors including sudden output**

shortfalls from conventional generators and a much slower decline in wind output. To the extent that changes in wind were a contributing factor during the passage of the February 26 cold front, that can be resolved by integrating the use of wind forecasting into electric system management, as ERCOT is planning to do.

2. **Wind is not dispatchable, but it is generally predictable, and therefore can be successfully and reliably integrated into electric system management.** Wind forecasting accurately predicted ERCOT's February 26 decrease in wind generation. This event illustrates that wind forecasting is an important tool for the successful management of large amounts of wind generation on a grid. ERCOT's wind forecasting system is under development and they plan to accelerate its implementation. When it is in place, such changes in wind output would not be expected to contribute to any system problems.

3. **Unlike other sources of generation that can go offline in 1/60th of a second, wind's declining output tends to be gradual over a matter of hours, giving system operators more time to respond to changes.** Fossil and nuclear power plants can and frequently do trip offline *instantaneously*, as the power outage on February 26 in Florida demonstrated. In ERCOT, 13 conventional generating plants instantaneously tripped offline during the week following February 26th. In the largest of these incidents, 420 MW. 500 MW, 540 MW, 582 MW, and 650 MW were instantaneously lost because a conventional generating unit tripped offline. The

February 26th incident was preceded by the loss of a 150 MW non-wind generating unit that tripped offline at 5:44 PM. In comparison, wind generation decreased steadily on February 26 by about 8 MW/minute, during a 3-hour interval.

4. **The event was caused by a combination of factors, one of which was non-wind generators falling short of their scheduled output.** The activation of responsive reserves and interruptible load reserves at 6:49 PM on February 26 immediately followed a 40-minute period during which conventional generation dropped by 350 MW relative to its schedule. Although wind was consistently below its scheduled output during this time period, from 6:27 to 6:50 wind output gradually increased by 40 MW relative to its schedule.

5. **Another factor that contributed to the event was the rapid rate of load increase that evening.** The load increase on the evening of February 26th was 3,150 MW larger than the previous evening's load increase. As a result, ERCOT's short-term load forecast underestimated the actual load at 6:45 PM by 1,185 MW.

6. **To sum up, over the 40-minute period preceding the start of load curtailment, wind generation declined by 80 MW relative to its schedule, non-wind generation decreased by 350 MW relative to its schedule, and load rapidly increased to a level that was 1,185 MW more than forecast.**

7. **The use of "demand response" is not unusual and is a proven tool in cost-effectively maintaining grid reliability.** ERCOT is a leader in the use of paid voluntaly

interruptible loads (demand response) to accommodate significant variations in load, the sudden loss of conventional generation plants, and to avoid subjecting customers to involuntary power outages. For example, on March 16th, 2008, ERCOT was forced to activate 625 MW of voluntary load interruption following the loss of 1172 MW when a nuclear generating plant instantaneously tripped offline. Frequency on the ERCOT grid dropped from 60 to 59.7, significantly worse than the drop from 60 to 59.85 Hz that was registered on February 26. According to ERCOT, this qualified as a potential NERC Disturbance Control Standard event, while the February 26th event did not. This event illustrates that all generation facilities are subject to unexpected shortfalls in output, and that demand response is a useful way to accommodate variations in supply and demand on the grid.

UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. RM10-17-000

DEMAND RESPONSE COMPENSATION IN ORGANIZED WHOLESALE ENERGY MARKETS

May 13, 2010

COMMENT OF THE FEDERAL TRADE COMMISSION

I. Introduction and Summary

The Federal Trade Commission (FTC) appreciates this opportunity to comment on the Federal Energy Regulatory Commission's (FERC's) Notice of Proposed Rulemaking (NOPR) regarding demand response compensation in organized wholesale energy markets.[1]

Demand response programs traditionally are viewed as mechanisms to pay customers to reduce their use of power below a normal ("baseline") level during periods when power grows scarcer. It is useful to consider such programs as giving customers the rights to power and then allowing customers to decide between using that

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[1] 75 Fed. Reg. 15362 (Mar. 29, 2010), *available at* http://frwebgate5.access.gpo.gov/cgi-bin/PDFgate.cgi?WAISdocID=483338499308+1+2+0&WAISaction=retrieve. Under demand response programs, participants can either exercise their rights to consume power or sell that power back to the grid.

power and reselling it to the wholesale market. FERC's NOPR takes that view, stating that the NOPR's "focus is on customers providing—through bids—demand response that acts as a resource [*i.e.*, as an energy seller] in organized wholesale energy markets."[2]

FERC then proposes standards for compensating these sellers. FERC reviews the variety of approaches to demand response compensation in the areas operated by regional transmission organizations (RTOs) and independent system operators (ISOs); discusses the need for reform in demand response compensation; and concludes that there is inadequate compensation for retail customers that supply demand response while paying time-invariant (*i.e.*, flat) retail rates. To remedy this inadequacy, FERC proposes that demand response be compensated at the level of the locational marginal price (LMP) applicable to each such customer providing demand response.[3] This comment demonstrates that policies to give electricity customers the right incentives to provide demand response will (1) allow demand response providers to sell power at an LMP that accurately represents social cost and (2) require firms to pay the same amount for their power, regardless of whether they use it or sell it to a demand response program. Stated differently, policies that give the wrong incentives may make it more profitable for demand response providers to sell power rather than consume it to produce socially desirable goods or services.

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[2] NOPR P 3.

[3] *Id.* PP 7-19.

We question the soundness of a policy that would pay companies the proceeds from the sale of power that they never bought in the first place. Such a policy would create situations in which a demand response provider would find it more profitable to sell its power rights (*i.e.*, provide demand response) than to consume that power, even though the value to society of consuming that power exceeds the power's cost to society. Our comment addresses FERC's question about how to compensate demand response provided by a retail electricity customer that pays a flat retail price for power. An efficient demand response compensation scheme allows the customer to sell power to which it has rights—at an LMP that captures the full social cost of the marginal unit of power—and to pay the usual retail price to acquire the power that it resells.[4] One way to implement this compensation scheme is to consider demand response to be a single buy-sell transaction that determines the compensation level by subtracting the retail price from the LMP.

Although there are reasons to conclude, as FERC does, that current compensation for demand response is insufficient to elicit efficient levels of demand response, this insufficiency does not stem entirely from the formu-

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[4] This is an implication of a more general principle that underlies, for example, hedging strategies that firms use to mitigate the risk of future price fluctuations. These strategies buy rights to a commodity on the futures market at the expected future price and then, when the futures contract matures, give the firm an efficient incentive to adjust its consumption by buying or selling at the spot market price. A discussion and an example appear in Section III and the Appendix to this comment.

las that RTOs and ISOs use (or propose to use) to compensate retail demand response providers. It also arises in significant part from a system that fails to set LMPs encompassing all of the social costs of electricity. Distortions of wholesale pricing—such as those stemming from the exercise of market power, from market power mitigation measures, or from the omission of other social costs—may cause the LMP to diverge from the efficient price. LMPs that internalize the full social costs of power are a necessary component of efficient compensation for demand response. The inclusion of full social costs in LMPs also has the added benefit of setting more efficient prices to guide decisions by all participants in wholesale electricity markets. To the extent that it is impractical to swiftly correct market flaws that make LMPs inaccurate, the efficient short-term response is unlikely to involve treating power as a free good. Rather, FERC should take direct action to adjust the compensation of demand response providers and articulate the conditions under which such interventions would be phased out.

The inaccuracy of current LMPs is a separate issue from the need to charge end-users the same price for power that they consume and for power that they sell. A policy approach that separates these issues and directly addresses each issue will be easier to design in the near term and to revise as necessary in the long term.

II. Interest of the Federal Trade Commission

The FTC is an independent agency of the United States Government responsible for maintaining competi-

tion and safeguarding the interests of consumers, both through enforcement of the antitrust and consumer protection laws and through competition policy research and advocacy. The FTC often analyzes regulatory or legislative proposals that may affect competition or allocative efficiency in the electric power industry. The FTC also reviews proposed mergers that involve electric and natural gas utility companies, as well as other parts of the energy industry. In the course of this work, as well as in antitrust and consumer protection research, investigation, and litigation, the FTC applies established legal and economic principles and recent developments in economic theory and empirical analysis. The energy sector, including electric power, has been an important focus of the FTC's antitrust enforcement and competition advocacy.[5] The FTC's competition advocacy program has produced two staff reports on electric power industry restructuring issues at the wholesale and retail levels.[6] The

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[5] *See, e.g.* Opening Remarks at the FTC Conference on *Energy Markets in the 21st Century: Competition Policy in Perspective* (Apr. 10, 2007), *available at* http://www.ftc.gov/speeches/majoras/070410energyconferenceremarks.pdf. FTC merger cases involving electric power markets have included the *DTE Energy/MCN Energy* (2001) (consent order), *available at* http://wwwftc.gov/os/2001/05/dtemcndo.pdf; and *PacifiCorp/Peabody Holding* (1998) (consent agreement), *available at* http://www.ftc.gov/os/1998/02/9710091.agr.htm. (The FTC subsequently withdrew the *PacifiCorp* settlement when the seller accepted an alternative acquisition offer that did not pose a threat to competition.)

[6] FTC Staff Report, *Competition and Consumer Protection Perspectives on Electric Power Regulatory Reform: Focus on Retail Competition* (Sept. 2001), *available at* http://www.ftc.gov/

FTC staff also contributed (as did FERC staff) to the work of the Electric Energy Market Competition Task Force, which issued a *Report to Congress* in 2007.[7] In addition, the FTC has held public conferences on energy topics, including *Energy Markets in the 21st Century* (April 10-12, 2007)[838] and *Carbon Offsets & Renewable Energy Certificates* (January 8, 2008).[9]

The FTC and its staff have filed numerous competition advocacy comments with FERC and participated in FERC technical conferences on market power issues. For example, in March 2007, the Deputy Director for Antitrust in the FTC's Bureau of Economics served as a panelist for a technical conference on FERC's merger and acquisition review standards under Federal Power Act Section 203 (Docket No. AD07-2-000). Similarly, the

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reports/elec/electricityreport.pdf; FTC Staff Report, *Competition and Consumer Protection Perspective on Electric Power Regulatory Reform* (July 2000), *available at* http://www.ftc.gov/be/v000009.htm (compiling previous comments from the FTC staff provided to various state and federal agencies).

[7] *See* http://www.ferc.gov/legal/fed-sta/ene-pol-act/epact-fina-rpt.pdf.

[8] Conference materials *available at* http://www.ftc.gov/bcp/workshops/energymarkets/index.shtml.

[9] Conference materials *available at* http://www.ftc.gov/bcp/workshops/carbonoffsets/index.shtml. Other programs have included the FTC's public workshop on *Market Power and Consumer Protection Issues Involved with Encouraging Competition in the U.S. Electric Industry*, held on September 13-14, 1999 (workshop materials *available at* http://www/ftc.gov/bcp/elecworks/index.shtm); and the Department of Justice and FTC workshop on *Electricity Policy*, held on April 23, 1996.

FTC submitted comments in December 2009 in FERC's proceedings on possible elements of a National Action Plan on Demand Response (Docket No. AD09-10-000)[10] and on transmission planning processes (Docket No. AD09-8-000).[11] In March 2010, the FTC filed a comment on performance metrics for RTOs and ISOs (Docket No. AD10-5-000),[12] and last month the FTC commented in response to FERC's Notice of Inquiry concerning integration of variable energy resources (Docket No. RM10-11-000).[13] The FTC also has commented on FERC's initiatives to promote wholesale electricity competition and on various state issues associated with restructuring the electric power industry.[14]

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[10] This comment is *available at* http://www.ftc.gov/os/2009/12/V100002ferc.pdf.

[11] This comment is *available at* http://www.ftc.gov/os/2009/12/V100001ferc.pdf.

[12] This comment is *available at* http://www.ftc.gov/os/2010/03/100319performancemetrics.pdf.

[13] This comment is available at http://www.ftc.gov/os/2010/04/V100009fercomment.pdf.

[14] *See, e.g.*, Federal Trade Commission, Comment before the Federal Energy Regulatory Commission on Wholesale Competition in Regions with Organized Electric Markets, FERC Docket Nos. RM07-19-000 and AD07-7-000 (Apr. 17, 2008), *available at* http://www.ftc.gov/be/v070014b.pdf. A listing of FTC and FTC staff competition advocacy comments to federal and state regulatory agencies (in reverse chronological order) is *available at* http://www.ftc.gov/opp/advocacy_date.shtm.

III. The Case for Making Demand Response Providers Pay the Retail Price for the Power They Resell at LMP

Demand response programs often assign each customer a baseline consumption level that attempts to capture the amount of power the customer would have used in the absence of the demand response program. Demand response programs then offer the customer a price per kilowatt-hour (kWh) of the baseline quantity that the customer does not use.

An example at the retail levels is the Peak Time Rebate program run by San Diego Gas & Electric. That program declares scarcity days on which it pays a customer 75 cents for each kWh that the customer's consumption is below a baseline calculated from average consumption in the days before the event.[15] It is clear that SDG&E, like many similar firms, does not charge customers extra during baseline-setting periods, when the company bundles valuable baseline rights with the power that customers use during the baseline-setting period. It is implicitly giving away valuable rights and should expect customers to consume too many of them.[16] SDG&E both sells the customer power[17] and runs

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[15] Specifically, SDG&E defines the baseline for a "weekday event" as "the total consumption for the hours of 11 a.m.-6 p.m. averaged over the three (3) highest days from within the immediately preceding five (5) similar non-holiday week days prior to the event." *See* http://www.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_PTR.pdf.

[16] For evidence that customers increase consumption to raise their baselines and get extra rebates in a very similar program, *see*

the rebate program that implicitly buys the power back. Thus, the 75-cent payment could be the resale proceeds net of the retail price at which the customer bought the power.[18]

In some wholesale markets, however, the "curtailment service provider" that administers the demand response program and pays the customer to reduce load is different from the firm that sells customers power at retail. Retail providers that simply bill customers for the power they use will typically have no reason to bill a customer for power that the customer resold before it passed through the customer's meter. Further, many entities conceive of demand response as programs that involve paying cus-

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Frank A. Wolak, "Residential Customer Response to Real-Time Pricing: The Anaheim Critical-Peak Pricing Experiment" (working paper, Stanford University, 2006), *available at* ftp://zia.stanford.edu/pub/papers/anaheim_cpp.pdf. We return to questions about pricing baseline rights in Section IV, *infra*.

[17] Like most utilities, SDG&E sells power to residential customers under a "requirement" contract that obligates it to sell the customer as much power as the customer wants at a predetermined price. Thus, SDG&E loses money on every kWh of power that it sells during periods of increased scarcity, when power is unusually expensive.

[18] SDG&E does not compensate customers at the wholesale price less the retail price from its increasing block residential retail rates. In other words, San Diego customers who use a lot of power pay more for their last unit of power than do customers who use only a little power. But the customer's consumption level does not affect the 75 cents/kWh payment. Thus, SDG&E's pricing is at best an approximation of the net demand response compensation that would arise if the customer bought power at the applicable retail price and resold it.

tomers to reduce consumption rather than paying them to resell power. For example, ISO New England's demand response program website says that "[d]emand response programs compensate large electricity users for reducing consumption when market prices are high or demand is high and system reliability is at risk."[19] Such a view makes it seem natural not to charge customers for the power they were paid not to use. We show below that this "natural" approach creates poor incentives. Thus, the central points of this section are that FERC is correct to conceive of demand response as the resale of power, and that FERC policy should ensure that customers pay for the power regardless of whether they use it or resell it.

FERC observes that some RTOs and ISOs favor compensating demand response at the level of LMP minus the retail power price if the retail price of power is fixed (time-invariant). The PJM market, which runs a wholesale electricity system covering the Mid-Atlantic region and extending west to Chicago, has been doing so for several years. Advocates of this position maintain that paying LMP without any such subtraction or purchase requirement will overcompensate demand response. Stated slightly differently, the concern is that demand response providers already receive a benefit because they do not pay their retail suppliers for power they would have consumed had they not provided demand response.

This concern about overcompensation is well founded. It is useful to view demand response as a provision that

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[19] *See* http://www.iso-ne.com/genrtion_resrcs/dr/index.html.

allows end-users to decide between consuming power themselves and reselling it. End-users have the appropriate incentives[20] if they pay the same price for power that they consume and for power that they sell. If customers have to pay the retail price for power that they use but pay nothing for power that they resell, then they will have incentives to resell power in situations in which it would be more beneficial to society for them to consume it.

The example in the Appendix illustrates this reasoning. It observes that efficient demand response compensation creates incentives for the customer to consume power from the grid whenever the marginal social benefit (MB) of consumption exceeds the marginal social cost (MC) of power, as approximated by the LMP. Formally, this is written as MB>MC. Note that subtracting the same number from both sides of the inequality—for example, the fixed cost of retail power under traditional rate regulation—does not alter the inequality, and firms that had a correct incentive to provide demand response before the subtraction retain that incentive after the subtraction. But if the retail customer is charged only for power that is consumed but not for power that is resold, then the inequality may not hold. Whenever the inequality is reversed, the retail customer has an incentive to resell power even when it would be socially more efficient to consume it.

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[20] Here, "appropriate" means efficient if the LMP equals marginal social cost.

Customers who pay for the power they consume, but not the power that they sell back to the grid, will have an incentive to consume power not when the marginal benefit exceeds the marginal cost, but when the marginal benefit exceeds the sum of the marginal cost and the retail price. Simple algebra shows that buying when the difference between the marginal benefit and the retail price exceeds the marginal cost is equivalent to buying when the marginal benefit exceeds the sum of the retail price and the marginal cost.[21] Thus, giving away for free the power that customers resell implicitly raises the price of consuming power above the efficient level. This will lead firms to provide too much demand response.

IV. Good Demand Response Compensation Schemes Facilitate a Transition Toward Better Rate Structures

Several FTC comments have emphasized the benefits of moving consumers away from traditional time-invariant and time-of-use pricing schemes that do not expose them to hour-by-hour fluctuations in the cost of power.[22] Demand response programs are a pragmatic,

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[21] If we charge the retail price P for just the power that firms consume, but not the power that they resell at the system marginal cost (MC), then firms will have an incentive to consume power whenever their marginal benefit less the price exceeds the marginal cost. Formally, that becomes MB-P>MC. If we add the retail price to both sides, we see that this is equivalent to saying that they will consume when MB>MC+P.

[22] *See, e.g.*, Comment of the Federal Trade Commission on Possible Elements of a National Action Plan on Demand Response, *supra* note 10; FTC Staff Report, *Competition and Consumer*

incremental step toward this goal. They can expose customers to the LMP during periods of increased scarcity, when time-invariant prices are least accurate and create the largest cross-subsidies. Demand response programs can be added to existing rates and regulatory infrastructure. Nevertheless, they should be considered an interim approach. Desirable demand response compensation should facilitate movement toward rate structures that correct all of the major flaws in the existing, legacy rate structure.[23]

Demand response programs do not fully correct these flaws when they fail to correctly define and price valuable rights to use power when it is scarce. Demand response programs implicitly buy those rights back from power consumers. An important, unresolved challenge in electricity policy is the efficient allocation of the right to use power at a predetermined price during periods when power is scarcer.[24] Example 2 in the Appendix illustrates how forcing flexible firms to pay for the option to buy power at the average cost during such periods can distort decisions. FERC staff acknowledges the chal-

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Protection Perspectives on Electric Power Regulatory Reform: Focus on Retail Competition, *supra* note 6, Ch. III.

[23] For further discussion of reasons why demand response programs should be considered only an interim step, *see* James Bushnell, Benjamin F. Hobbs, and Frank A. Wolak, "When It Comes to Demand Response, Is FERC its Own Worst Enemy?," 22:8 Electricity J. 9 (2009).

[24] *See, e.g.*, Severin Borenstein, "Customer Risk from Real-Time Retail Electricity Pricing: Bill Volatility and Hedgability," 28:2 Energy J. 111 (2007).

lenges of allocating property rights ("baselines"): "The measurement of demand reductions associated with incentive-based demand response programs has proven to be a difficult and controversial problem The key measurement issue is how to calculate the level of consumption that would have occurred if the participant had not curtailed consumption—*i.e.*, the customer baseline level. Once the customer baseline is determined, the level of reduction is calculated by subtracting the actual demand from the estimated baseline normal demand.
A key problem with most estimation methods is the potential for gaming—participants may bid into the market or state that they will curtail when they would already be shut down for the day."[25] We agree that bundling free baseline rights with power is fraught with difficulties, and we encourage movement toward approaches that sell these rights at appropriate prices.

We are concerned that it will be difficult to change obsolete, inefficient retail rates if demand response is viewed as a single transaction that assumes that the customer buys power under the traditional rate structure. FERC should consider whether it is feasible to compensate demand response at the LMP and to have demand response providers pay for the power they resell to the demand response program under the terms of the retail contract they choose. This would allow demand response programs to succeed without creating new institutional

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[25] FERC Staff Report, *Assessment of Demand Response & Advanced Metering*, at 73, Docket No. AD06-2-000 (2006), *available at* http://www.ferc.gov/legal/staff-reports/demand-response.pdf.

constituencies for flawed, obsolete pricing and raising obstacles to the adoption of improved (dynamic) retail pricing and of better-defined property rights.

V. Efficient Compensation for Demand Response Requires Adjustments to LMP

Even if a demand response program defines property rights correctly and charges the same price for the power that retail customers consume and the power that they resell, using LMPs that misstate the true marginal social cost of power will still lead to socially inefficient results. Social marginal cost prices include the marginal cost both to the producer and to the rest of society. Costs to the rest of society include, for example, the cost of pollution. Pricing at the social marginal cost gives firms an incentive to generate power only when its benefits to society outweigh its costs to society, yielding maximum welfare.

Nevertheless, if LMPs omit important social costs (such as environmental degradation), then LMPs understate social marginal cost. This is currently the case with LMP calculations. For example, if power prices do not include the costs of the generator's pollutants, the LMP will fall short of the social marginal cost of power generation.[26] Similarly, market power can inflate prices and market mitigation measures (such as offer caps) can suppress price changes, both of which cause LMPs to diverge above or below the efficient price.

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[26] Environmental policies that put prices on sulfur dioxide emissions from power plants nationwide and on nitrogen oxides in certain regions are an important step toward making LMPs reflect social costs. Other important pollutants remain unpriced.

Thus, current LMPs may understate the social cost of power during greater scarcity periods. Giving demand response program participants an extra incentive equal to the retail cost of power attempts to correct for this through the use of a blunt, interim policy instrument. A program that allows customers to resell power that they did not pay for fails to calibrate the adjustment to demand response incentives in a way that corresponds to the magnitude of the distortions in wholesale power prices. Several potential effects of such a program are problematic. The program:

- could create the largest extra incentive to provide demand response in places where the most aggressive environmental interventions have created the highest retail rates but also have internalized most pollution costs;

- does not provide a way to phase out this interim, imprecise effort to increase compensation for demand response as improved policies correct flaws that distort LMPs;

- does not compensate other actions that reduce emissions, such as energy efficiency programs or pollution controls; and

- does not accommodate any natural ways to adjust the benefits of giving away retail power as the emissions profile of the marginal producer or the level of scarcity in the system changes.

If FERC needs an interim solution, it should not implement a program allowing demand response providers

to pay nothing for the power they resell. Rather, FERC should take direct action to adjust LMPs (or, if necessary, the compensation of demand response providers), and should articulate the conditions under which such interventions would be phased out.

In the longer term, policy makers can provide more efficient compensation for demand response by taking steps to improve market operations and make LMPs more accurate. These steps include (1) adjusting LMPs to better reflect the full social costs of electricity, (2) improving the accuracy of retail pricing and otherwise facilitating greater demand elasticity (to curtail potential market power), and (3) reducing dependence on offer caps and capacity markets.

Appendix: Examples

Example 1: Charging for Power Consumed, but Giving Away Power That Is Resold, Can Create Flawed Incentives

Consider a firm that can convert a megawatt-hour (MWh) of electricity into a product worth $100. For simplicity, assume that the firm has no costs other than the cost of the electricity it uses. This example uses the phrase "operate" to mean "consume exactly one MWh." Thus, $100 is the marginal benefit of the firm's operating and consuming one MWh of power. The firm has a contract that charges it $60/MWh for power on any afternoon. Consider an afternoon when the LMP is $90/MWh. We reach an efficient allocation if the firm operates whenever the marginal benefits of its operation exceed the marginal cost (which is the LMP). Because the marginal benefit ($100/MWh) exceeds the marginal cost (*i.e.*, the LMP of $90/MWh), the firm should operate. If the firm has to pay $60 for each MWh it consumes or provides as demand response, the $40/MWh it can earn from operating outweighs the $30/MWh it can earn from providing demand response. In that case, the firm will operate, which is the choice that yields the greatest benefit to society.[27] But if the firm pays nothing for the

[27] This assertion holds for any fixed price "P": the firm will make the right choice to operate if it earns $100-P for operating and $90-P for providing demand response, because it will operate whenever (100-P)>(90-P)—which in turn can be simplified by subtracting 90 from both sides and adding P to both sides to yield a condition that is always true, namely, 10>0.

power that it resells as demand response, then it will earn $90/MWh from providing demand response, which is far more attractive than the $40/MWh it can earn from operating. It would be more efficient for society, however, if the firm operated instead of reselling the power. Charging this firm nothing for the power that it resells as demand response gives it an inefficient incentive to provide demand response whenever the LMP is greater than $50/MWh and less than $100/MWh.

Example 2: The Importance of Defining Property Rights Appropriately

Demand response programs often are added on top of existing rate structures that do a poor job of defining and pricing the property right to use power during periods when wholesale power is expensive. These poorly defined property rights are typical of rates that are time-invariant or otherwise prevent customers from experiencing day-to-day, hour-to-hour variations in costs.[28] By contrast, this problem does not exist when retail customers pay real-time prices, nor does it arise when they can decide whether to buy price insurance.[29]

Time-invariant retail pricing forces customers to buy a bundle of two products—electric power and mandatory insurance against price variability. The insurance be-

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[28] Traditional time-of-use pricing—which offers the same peak and off-peak prices every day within a season—exhibits a muted version of the same flaws.

[29] Borenstein, *supra* note 24, discusses the effectiveness of appropriate rights definitions.

stows on customers a valuable, unlimited right to use high-cost power at an averaged-out price during high-cost periods. The costs of this ill-defined, ill-priced right are spread across all the customers on the rate, regardless of whether they want that right or the responsibility to pay for it. The cost of insurance reflects costs of building and operating a system that can handle overconsumption of power during high-cost periods that occur only because customers do not have to pay the true costs of power.

Demand response programs begin to address this overconsumption. A power system with time-invariant prices subsidizes power consumption during high-cost periods and penalizes consumption during low-cost periods. The example below illustrates how a combination of demand response and time-invariant retail prices can alleviate some, but not all, of the losses to society stemming from time-invariant retail prices. The example does not capture the fact that, if there is enough demand response, then peak-period prices will fall and the cost of price insurance will drop.

Consider the following example: There is an electricity market where the typical customer buys 1 unit on low-demand days when the LMP is $50/MWh and buys 2 units on high-demand days when the LMP is $250/MWh. For this example, we assume that there are 8 low-demand days for every high-demand day. Thus, the time-invariant or average price is $90/MWh.[30]

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[30] [(8 days x 1 unit x $50) + (1 day x 2 units x $250)]/10 total units = $90. For the sake of simplicity, we assume away the distribu-

Consider a firm in that market that can convert 1 MWh of power to a product worth $85. The firm should operate on every low-demand day because that creates $35/MWh of social surplus, and it will have incentives to do so if it buys power under a real-time pricing system that offers it power at the LMP of $50/MWh.

By contrast, if the firm is on time-invariant pricing without demand response, it will never operate and society will never realize any of the social benefit that its operations would have created. The problem arises because time-invariant pricing forces the firm to buy a price hedge bundled with its power. In this example, the cost of power plus the hedge is greater than the benefit to the firm from consuming power.

If the firm buys power under a time-invariant pricing system, but with the kind of demand response program discussed in this comment, then the firm likely will operate just enough to earn the right to sell back power during the high-demand period. It is thus cashing in the hedge, but flawed rules—such as "you qualify to sell 2 MWh in the demand response program if you consumed 1 MWh on the low-demand day before the high-demand period"—mean that the firm in this example finds that its most profitable strategy is to operate only on low-demand days before high-demand days. Such a program, however, would create efficient incentives for firms that get more benefit from consuming each kWh than the $90/MWh that they pay when they consume power under the flat rate.

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tion utility's costs, so that retail prices are just the average of the appropriate wholesale prices.

UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. RM10-17-000

DEMAND RESPONSE COMPENSATION IN ORGANIZED
WHOLESALE ENERGY MARKETS

May 13, 2010

Comments of the Organization of MISO States

I. Background

On March 18, 2010, the Federal Energy Regulatory Commission (Commission) issued a Notice of Proposed Rulemaking in the above captioned docket. The purpose of the proposed rule is to establish a requirement that RTOs "must pay demand response resources, in all hours, the market price for energy, i.e. full LMP, for demand reductions made in response to price signals."[1]

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[1] Notice of Proposed Rulemaking, 130 FERC ¶61,213 at P 11 (footnote omitted).

II. Comments

A. The Organization of MISO States Continues to Support its Position that the Correct Compensation to ARCs for Retail Load Reductions is LMP-Retail Rate.

On October 2, 2009, the Midwest ISO made a compliance filing in Docket No. ER09-1049-002. The filing contained proposed tariff revisions which have the objective of accommodating the participation of Aggregators of Retail Customers (ARCs) in Midwest ISO markets. In that filing, the Midwest ISO proposed: (1) To compensate ARCs by subtracting the retail rate paid by participating retail customers from the LMP, and (2) To directly assign the costs of payments made by the Midwest ISO to ARCs to the Load Serving Entity (LSE) that provides retail service to the participating retail customer.

The Organization of MISO States ("OMS")[2] submitted Comments to the Commission in support of that filing, in particular in support of the proposed com-

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[2] The OMS is a non-profit, self-governing organization of representatives from each state with regulatory jurisdiction over entities participating in the Midwest ISO. The purpose of the OMS is to coordinate regulatory oversight among the states; to make recommendations to the Midwest ISO, the Midwest ISO Board of Directors, the Commission, other relevant government entities and state commissions as appropriate; and to intervene in proceedings before the Commission to express the positions of the OMS member agencies.

pensation mechanism.[3] The OMS continues to support the compensation formula (LMP-Retail Rate) and the direct assignment of costs of payments made to ARC as is being proposed by the Midwest ISO. The OMS urges the Commission to consider these two issues in tandem, rather than focusing on ARC compensation in isolation.

B. Payment of the full LMP to ARCs as Proposed by the Commission Would Result in a "Distortionary Subsidy" to ARCs and Participating Retail Customers.

The economics of demand response from the perspective of wholesale markets are relatively simple. LMPs in organized wholesale market are based on marginal costs whereas retail rates are typically fixed and based on average costs. At certain times, retail rates are lower than LMPs. Depending on each individual customer's elasticity of demand, some customers would likely curtail certain uses of electricity during these time periods if they faced the higher wholesale LMP rather than the lower retail rate. Therefore, retail customer consumption decisions are "inefficient" during these hours. This is especially a concern during periods when LMPs are relatively high and the differential between LMPs and retail rates is significant.

The policy objective of accommodating ARC participation in wholesale markets is to provide a window

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[3] Comments of the Organization of MISO States, Docket ER09-1049-002, November 5, 2009.

to wholesale market LMPs for retail customers. This allows retail customers to make consumption decisions during these hours based on the higher wholesale market LMPs rather than the lower retail rates.

An "efficient" payment to the retail customer is the amount necessary to provide sufficient incentive for customers to make consumption decisions as if they were facing the wholesale rate and thus not to exercise their option to purchase at the lower retail rate. The question at hand becomes: How much does the retail rate have to be increased so that retail customers behave as if they are facing the wholesale LMP? Because the retail customer is already facing the retail rate, the efficient payment is represented by the difference between the LMP and the retail rate.

The payment of any amount in excess of this difference to the ARC, such as the full LMP would result in a "distortionary subsidy" to the retail customer and the ARC. The concept that the payment of the full LMP to ARC's is inefficient and would result in market distortions is well-known has been discussed in various reports and in comments to the Commission in other proceedings.[4] The payment of the full LMP distorts consumer behavior and would result in ineffi-

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[4] See for example, "Fostering Economic Demand Response in the Midwest ISO," The Brattle Group, December 30, 2008, at page 31; Motion for Leave to Answer and Answer of the Electric Power Supply Association and White Paper by Professor William W. Hogan, Docket No. EL09-68-000, October 30, 2009; Motion to Intervene and Protest of Robert L. Borlick Opposing PJMs Proposed Tariff Changes, Docket No, EL09-68-000, September 16, 2009.

cient decisions to curtail load. In addition, the subsidy would have to be recovered from non-participating customers. It is clear that the proposed rule would replace one inefficient price signal with a different inefficient price signal and would result in a subsidy to ARCs and participating customers.

If the Commission were to adopt the proposed rule, state commissions and LSEs could correct this distorted price signal by revising retail tariffs for customers that do business with ARCs in order to charge the retail rate to participating customers for energy which was not consumed or metered as a result of load reductions. However, these tariff revisions could be complex, time consuming and could possibly involve legal issues—namely, billing retail customers for energy which they have not consumed and which was not metered. LSEs would be forced to develop and implement billing mechanisms for participating retail customers in order to accommodate billing information from outside of their normal metering and data acquisition systems from the RTO's Measurement and Verification system. Ironically, state commissions would be faced with the task of revising retail rate structures in order to correct a price distortion created by a wholesale market pricing mechanism which was intended to improve price signals.

The simpler mechanism is the one proposed by the Midwest ISO which uses the RTO's settlement system to combine these two pieces into the compensation formula by subtracting the retail rate from the LMP when it makes payments to ARCs.

The review of a policy issue currently facing the state commissions and LSE may be useful to the Commission to help it understand the practical shortcomings of the proposed rule. Many state commissions and LSEs are presently evaluating the installation of smart meters. One of the objectives of smart meters is the provision of better price signals to retail customers that more accurately reflect wholesale market prices. Let us suppose that a state commission approves the installation of smart meters for its large commercial and industrial customers and establishes a retail rate structure which has hourly variable energy charges equal to the wholesale market LMP. If such a rate structure were to be implemented, the differential between the wholesale market LMP and the retail rate would vanish as would the need for ARCs to bridge this price difference. However, under the proposed rule, an ARC would still find it profitable to sell load reductions from these customers into the wholesale market, even though the retail rate is exactly equal to the LMP and these customers are already receiving the "correct" price signal and are making efficient decisions concerning their consumption of electricity. The efficiency gains expected of the investment in smart meters based on the ability to provide more complex retail pricing structures that more closely follow wholesale LMPs would be diminished by the resultant subsidy to ARCs and participating customers. An efficient retail price signal made possible by smart metering technology would be replaced with an inefficient price signal in the wholesale market.

The example discussed above shows that the need for ARCs may be temporary, as there will be increasing amounts of customers on real-time rates or rates that more closely follow wholesale prices. Indeed, this year both the Midwest ISO and the PJM Interconnection are developing methods for incorporating Price Responsive Demand (PRD) into their markets. Once LSEs are able to take advantage of these PRD elements in wholesale markets, the opportunities for ARCs are likely to diminish.

C. Compensation for Demand Response Resources Must be Considered in Conjunction with the Recovery of the Cost of Payments made by RTOs to ARCs.

Retail rate schedules provide an option to customers to purchase electricity at the retail rate. Depending on the retail rate and the value of the intended use of the electricity, customers choose to exercise this option or not to exercise the option. ARCs provide a payment to the participating customers to give them an incentive not to exercise this option. No energy changes hands and no additional energy is produced.

The RTO is not indifferent to this transaction. This is because the RTO must be revenue neutral in its daily settlements and it must now make a payment to the ARC while the RTO's other costs and revenues remain the same. Therefore, the RTO must have a source for this payment.

There are two potential sources. One is to socialize the cost of the payment across the RTO as an uplift

charge to all LSEs. The second is to directly assign the cost to the LSE that provides service to the participating retail customers.

In its proposal to integrate ARCs into its energy markets, the Midwest ISO proposed to directly assign the cost of this payment to the LSE which provides retail service to each participating customer. OMS supports the direct assignment of these costs as proposed by the Midwest ISO. Direct assignment of the cost of this payment is appropriate as the arbitrage opportunities available to ARCs only arise due to differences between an individual LSE's retail rates and wholesale market LMPs. Direct assignment of these costs will create an incentive for individual LSEs to more closely align their retail rates with wholesale market LMPs.

If the cost of this payment is directly assigned, an LSE will face the same costs in the wholesale energy market whether or not its retail customers that participate with an ARC consume MWhs or provide these MWhs as load reductions to the ARC. Either way, the LSE pays for those MWhs. However, if its retail customers provide load reductions to an ARC, the LSE's metered retail energy sales go down, and its retail revenue goes down. The LSE has a reduction in retail revenue but its wholesale market costs remain the same. The LSE is no longer indifferent to the participation of its retail customers with an ARC. Subtracting the retail rate from the LMP effectively restores these lost retail revenues to the LSE and makes the LSE indifferent as to whether its customers

consume electricity at the retail rate or provide a load reduction to the ARC.

If the amount of lost retail revenue was guaranteed to be small, LSEs and the State Commissions might be willing to absorb the loss. However, the Commission is definitely advocating a bigger role for ARCs in its orders and in its Strategic Plan. Expectations are that demand response will be playing a bigger role in organized energy markets in the future. LSEs and State Commissions are more likely to support the provision of demand response by ARCs in the RTO markets if non-participating customers do not have to bear additional costs as a result.

The OMS does not support the uplift of the costs of payments to ARCs. This would penalize states and LSEs which have implemented and or are planning to implement improved and innovative retail rate structures using smart metering technology.

D. Adoption of the Proposed Rule would Encourage State Commissions to Opt Out of RTO Demand Response Programs.

As the Commission is aware, numerous state commission members of the OMS have issued orders either prohibiting or placing restrictions on the operation of ARCs in their states. The OMS will let these orders speak on their own. However, it should be clear to the Commission that state commissions and LSEs have significant concerns that the potential costs for non-participating customers may exceed the benefits that ARCs can provide to their states and to par-

ticipating customers. State commissions will have a significant disincentive to support the participation of ARCs in RTO energy markets and in their states if the proposed rule is adopted.

In Order 719-A, the Commission clarified that it was not challenging "the role of states and others to decide the eligibility of retail customers to provide demand response."[5] The Commission also stated that "we leave it to the appropriate state or local authorities to set and enforce their own requirements."[6] In the Commission's order in Docket No. ER09-701-000/ ER09-701-001, which involved proposed tariffs of the PJM Interconnection and (in part) whether state authorities could condition eligibility in an RTO's demand response programs, the Commission reiterated that "Order No. 719-A thus clarified that relevant retail authorities retain substantial flexibility in establishing requirements for eligibility of retail customers to provide demand response."[7]

As stated earlier in these comments, any requirement by the Commission for RTOs to compensate demand response resources at full LMP is likely to lead state and local regulatory authorities to condition eligibility for demand response participation by ARCs in their states such that ARCs and participating customers do not receive a payment equal to the full LMP In this sense, then, due to the alignment of

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[5] Order 719-A, 128 FERC ¶ 61,059, P 49.

[6] *Id.* P 54.

[7] *PJM Interconnection, LLC*, 128 FERC ¶ 61,238, P 22.

wholesale and retail jurisdictions in this matter, whatever payment the Commission requires in an organized wholesale market can be modified by the relevant retail regulatory authorities.

However, there is an easier fix. Compensation mechanisms such as the one proposed by the Midwest ISO resolve the issues associated with lost retail revenues for LSEs, eliminates State Commission legal concerns about the revision of retail rate schedules and billing retail customers for energy which is not metered or consumed, and results in an efficient price signal for ARCs and retail customers that are offering load reductions into RTO energy markets. The Commission should not adopt a rule which would preclude the approval of such a compensation mechanism by RTOs.

OMS understands that some state commissions may wish to provide an additional incentive for ARCs to operate in their states through the payment of the full LMP. OMS is not opposed to such incentives if it is done on a voluntary basis on a state by state basis, and if the costs of the incentive are directly assigned to retail customers within those individual states.

III. Conclusion

In its recently released Strategic Plan, the Commission established a goal of eliminating barriers to participation by demand resources in organized wholesale retail markets. The OMS supports this objective. Third-party ARCs will likely play a large role in implementing demand response resources because of

their ability to achieve economies of scale, implement new technology and provide demand response services to customers that take retail electric service from multiple LSEs. ARCs can also provide a competitive check on LSEs in the provision of demand response to customers. However, the Commission must remain cognizant that the vast majority of demand response programs have been and will likely continue to be developed and implemented by LSEs under the auspices of the State Commissions.

Implementing market structures that allow for the participation of ARCs should not include the establishment of inefficient price signals which distort demand response behavior and result in a cost burden on other customers. Further, State Commissions and LSEs should not be forced to make expensive and complex changes to retail tariffs and billing systems in order to accommodate the participation of ARCs. This would likely result in State Commissions either taking action to "opt-out" or declining to "opt-in" under the provisions approved in Order 719-A.

For these reasons, the OMS urges the Commission not to adopt the proposed rule.

The OMS submits these comments because a majority of the members have agreed to generally support them. Individual OMS members reserve the right to file separate comments.

Respectfully Submitted,

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Dated: May 13, 2010

UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. RM10-17-000

DEMAND RESPONSE COMPENSATION IN ORGANIZED WHOLESALE ENERGY MARKETS

[May 13, 2010]

COMMENTS ON NOTICE OF PROPOSED RULEMAKING OF PJM INTERCONNECTION, L.L.C.

Pursuant to the Federal Energy Regulatory Commission's ("Commission") Notice of Proposed Rulemaking ("NOPR")[1] issued on March 18, 2010 in the above-captioned proceeding, PJM Interconnection, L.L.C. ("PJM") respectfully submits these comments which are largely based upon PJM-specific observations and concerns. The answer to the question of what constitutes appropriate compensation for economic load response in the wholesale energy market is inherently intertwined within the complexities of the relationship between wholesale prices, the structure of retail rates and ratemaking, and the extent and nature of the retail obligation to serve—factors which vary state by state and in some cases by individual utility

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[1] *Demand Response compensation in Organized Wholesale Energy Markets*, Notice of Proposed Rulemaking, Docket No. RM10-17-000, 130 FERC ¶ 61,213 (March 18, 2010) (hereinafter "NOPR").

within a state. Consequently, the Commission's proposal to make direct, explicit payments to demand response providers, in all hours, at the prevailing wholesale market price for energy for reductions,[2] may be appropriate under some retail rate structures, but not necessarily appropriate under other retail rate structures. PJM believes that effective coordination between the wholesale prices and demand response compensation and retail rate structures markets is required to ensure economically efficient incentives for, and compensation to, demand response in wholesale energy markets ("incentive payments"). The implication of the necessary coordination between wholesale and retail levels is the review and potential action by Relevant Electric Retail Regulatory Authorities ("RERRAs") to account for wholesale demand response compensation at the retail level to ensure efficient incentives for demand response.

At the outset, these comments will present an update of current demand response capability in the PJM footprint. Next, these comments consider demand response compensation in the context of retail rate structures. These comments further consider the associated methodology for allocating costs associated with direct payments made to demand response at the wholesale level, and address some of the various competing impacts of demand response compensation equal to LMP at the wholesale level on retail markets. Finally, these comments consider the Commission's

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[2] NOPR at P 1.

proposal in the context of wholesale and retail integration of Price Responsive Demand ("PRD").

I. Introduction and Background

The purpose of this NOPR is to obtain industry reaction to the Commission's proposal to require Independent System Operators ("ISOs") and Regional Transmission Operators ("RTOs") that permit demand response providers to participate as resources in organized energy markets to pay such providers in all hours the market price, which is the Locational Marginal Price ("LMP")[3] in PJM. According to the NOPR the need for the proposed rule arises because after various efforts "to address barriers to and compensation for demand response participation, demand response providers collectively play a small role in the wholesale markets."[4] The Commission notes that it has issued orders in recent years approving various types of ISO and RTO demand response programs, and that the Commission has previously allowed a system-by-system approach to compensating demand response providers participating as resources in ISO/RTO day-ahead and real-time wholesale energy markets.[5]

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[3] Capitalized terms used and not otherwise defined herein have the meaning set forth in the Amended and Restated Operating Agreement of PJM ("PJM Operating Agreement"), PJM Open Access Transmission Tariff ("PJM Tariff") and PJM Manuals.

[4] NOPR at P 9.

[5] *Id.* at P 7-8.

While the Commission looks to PJM as a case study in the NOPR,[6] PJM opines that its experience with demand response providers may not necessarily support the requirements of other ISOs/RTOs. The Commission notes that it did reject a previous request to prevent a demand response compensation decrease from occurring as per the terms of PJM's then-existing tariff, but in doing so, it also "encouraged PJM and its stakeholders to continue analyzing the effectiveness of PJM's demand response program with the decreased payments for demand response."[7] Additionally, within the context of this NOPR, the Commission terminated the most recent docket addressing demand response compensation issues within PJM, but did take administrative notice of the record in that proceeding "so that parties in that proceeding need not re-file affidavits or other evidence introduced there"[8] in this proceeding.

In PJM's Supplemental Report and Submittal in Support of Further Commission Action, PJM pointed out that while a number of factors, such as implementation of new customer baseline rules, normal operations reviews, declining wholesale market prices in the

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[6] *Id.* at P 10.

[7] *Id.*

[8] *Id.* at P 23 (referring to *PJM Interconnection, L.L.C.*, Docket No. EL09-68-000). Given the incorporation of the prior record, PJM will not restate the various issues and concerns that led it to seek a limited departure from its prior approach of deducting the generation and transmission component of retail rates in the compensation it provides to demand response providers.

second half of 2008, and the expiration of the incentive program led to a decline in settled economic demand reductions between 2007 and 2008, the number of megawatts registered as Economic Load Response either remained stable or increased during the 16 months following the end of the incentive payment.[9] This means that the number of end-user sites capable of changing usage in response to wholesale market price signals continued to grow even as wholesale energy prices have fallen and additional rules to ensure market integrity were implemented. PJM believes that the growth in the number of end-use sites able, through their demand response providers, to "see" the wholesale price, react to the wholesale price, and get value from the wholesale market for that reaction is more significant than the number of decisions to reduce usage in response to price. These economic load response participants also do not include the end-use customers in restructured states that are price responsive, i.e. these end-use customers base energy purchase decisions on the Day-Ahead LMP or the Real-Time LMP. Moreover, during the period from June 1, 2006 to the present, the number of megawatts participating in PJM's capacity market has increased

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[9] *See PJM Interconnection, L.L.C.*, Supplemental Report and Submittal of PJM Interconnection, L.L.C. in Support of Further Commission Action on Rehearing at 4, Docket No. EL09-68-000 (August 26, 2009) ("August 26 Supplemental Report"). The August 26 Supplemental Report was originally filed in the proceeding, *PJM Industrial Customer Coalition v. PJM Interconnection, L.L.C.*, Docket No. EL08-12-000, however the Commission instituted a docket change, assigning new Docket No. EL09-68-000.

more than sevenfold from 1,245 MW to 7,294 megawatts; and, the number of active demand response providers, known in PJM as Curtailment Service Providers ("CSPs"), increased to 60. These latter improvements are no doubt the result of the institution of the Reliability Pricing Model ("RPM") which provided a three year forward revenue stream for demand response resources—a factor which was missing in prior PJM capacity constructs. Additionally, the number of end-use sites qualified to provide Synchronized Reserve has grown to 83, which is a result of enhancements to PJM market rules to provide demand response resources the opportunity to participate in PJM's Ancillary Service markets.

Given this record of growth in demand response resources technically capable of responding to prices, and the fundamental need for customers taking service under fixed rate retail structures to face the same incentives as customers taking service under dynamic or LMP-based retail rate structures, PJM continues to believes that economic load response compensation at the wholesale level must be coordinated with competitive and regulated retail rate structures to ensure appropriate and efficient incentives for demand response are embedded in wholesale energy markets.

II. Appropriate and Efficient Demand Response Compensation is Dependent Upon the Retail Rate Structure

The value of 1 MWh of energy in the wholesale market, whether it comes from generation or from demand response, is the prevailing LMP. In thinking

about the discussion surrounding the compensation of demand response, two central questions are the manner in which the value of demand response accrues to market participants associated with demand response —whether it is through an explicit, direct payment from the wholesale energy market or indirectly through avoided cost savings, and to which market participants does the value of demand response accrue.

A. Retail Rate Structures in which Direct Compensation at LMP is Efficient and Appropriate

Consider retail customers that already pay a fixed price or LMP for a fixed quantity of energy, whether they consume that energy or not, or who have otherwise engaged in such forward contracts for a fixed quantity of energy. If a customer buying energy under this retail rate structure does not consume the energy it has already purchased, and unwinds its position in the wholesale energy market, a direct payment for energy not consumed at LMP allows the customer to capture full wholesale market value of energy not consumed. This is consistent with the fundamental tenets of the two settlement system between the Day-ahead and Real-time Energy Markets present in PJM. Load Serving Entities ("LSEs") that purchase a quantity of power in the Day-ahead Market may in the Real-time Market not consume all of the power purchased in the Day-ahead, and the difference between Day-ahead and Real-time consumption will be settled at the prevailing Real-time LMP

Regulated or competitive, fixed price retail rate structures could potentially evolve to mirror the fixed

quantity contract described in the previous paragraph. For the purposes of demand response, the RERRA or competitive supplier could design a rate structure such that demand response, defined as the difference between the customer baseline load ("CBL") and metered load, would be billed to the customer for the amount at the retail rate. It is PJM's understanding that such a rate structure is not standard, and would require action on the part of competitive suppliers and RERRAs to implement. Under such a rate structure, compensation at LMP in the wholesale market allows the demand responder to capture the full market value of demand response through the direct payment.

B. Retail Rate Structures in which Direct Compensation at so-called "LMP minus G" is Efficient and Appropriate

A more traditional and standard retail rate structure for fixed rate retail customers is one in which the customer is only charged for energy consumed or metered and does not necessarily purchase the entitlement to consume on a forward basis.[10] Therefore, the direct payment of full LMP at the wholesale level would be the equivalent of providing these customers with a free option to sell power they never purchased at a full LMP market price. For these customers,

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[10] The details of exactly what constitutes the "obligation to procure" (and the ratemaking recovery of costs to the LSE associated with same) can vary from state to state and even by customer class. Provisions such as demand ratchets and other retail contractual provisions can impact the nature of an individual retail customer's retail procurement of electricity.

a compensation mechanism equal to the LMP minus the generation portion of the applicable retail rate ("LMP-G") is one means to ensure consistent and equitable treatment of customers purchasing power under the traditional, standard rate structure with LMP-based customers, customers with fixed quantity contracts, and other Market Participants. Basically, for fixed rate customers, the demand response resource receives a direct payment of LMP less the generation component of retail rates from the wholesale market, and then experiences an additional avoided cost of the generation component of retail rates by not consuming energy at the retail level, for a total value of LMP accruing to the demand resource.[11]

An example helps illustrate this principle. Consider a load that pays a fixed retail rate with a generation portion of that rate equal to $120/MWh. The load provides 1 MWh of demand response when the LMP equals $150/MWh. The load, by reducing usage 1 MWh, avoids the $120/MWh generation portion of the retail rate from a wholesale energy market perspective. If the load also receives "LMP-G" as a direct payment which is equal to $150/MWh $120/MWh = $30/MWh, then the total compensation accruing to the load engaging in 1 MWh of demand response is exactly equal to the value of that demand response of $150/MWh, but accrues through two avenues: avoided cost of $120/MWh and a direct payment of $30/MWh through the wholesale market.

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[11] August 26 Supplemental Report at 23.

The same principle discussed above applies to load being served by a LSE at a retail rate that is equal to the prevailing LMP. From the demand responder's perspective, the $150/MWh value of energy reduced by the 1 MWh of demand response accrues to the demand responder entirely through the avoided cost of $150/MWh as the "LMP-G" payment is equal to $150/MWh - $150/MWh = $0/MWh.

To provide a direct payment at LMP from the wholesale market under this rate structure would confer compensation through avoided cost and direct payment in excess of the value of energy. For the fixed price customer in the example above, the customer would avoid the fixed rate of $120/MWh, plus it would receive the direct payment of $150/MWh, which results in $270/MWh accruing to the demand responder—this is well in excess of the market value of energy reduced of $150/MWh. Under a compensation mechanism that provides a direct payment of the entire market price, LMP plus the avoided cost distorts demand response incentives in such a manner as to inefficiently encourage additional demand response at lower market prices. In the above example, customers would be responding as if the market price were $270/MWh rather than in response to the actual market price of $150/MWh.

PJM encompasses 13 states and the District of Columbia, which complicates economic load response compensation policy. While compensation for Economic Load Response equal to the LMP regardless of retail rate structure is appealing because it exactly

equals the compensation paid to generation resources, as discussed below, there are myriad of wholesale and retail implementation details that will require Commission review, consideration and coordination with the RERRAs, in addition to potential action at the RERRA level.

III. Appropriate and Efficient Demand Response Compensation Requires Consideration of How Direct Wholesale Market Payments are Allocated

As the Commission determines the policy to compensate demand resources in the wholesale energy market, PJM requests that the Commission consider the related methodology for allocating costs associated with direct payments made to demand response in the wholesale energy market. In order to avoid large wealth transfers from loads that do not engage in demand response activity to loads that do provide demand response, PJM believes that appropriate and efficient demand response compensation may require coordination between the Commission, RERRAs, competitive retail suppliers, and other RTOs, and possibly action on the part of RERRAs and competitive suppliers. Otherwise, if there is no coordination or supporting RERRA or competitive supplier action, as necessary, the payment of the incorrect amount of economic load response compensation may significantly and unnecessarily increase the total dollar amount that PJM will need to charge PJM Market Participants, result in large cost shifts among Market Participants, and/or distort otherwise efficient incentives in the wholesale energy market.

Under the existing PJM Economic Load Response Program ("Economic Program") compensation and cost allocation structure, each dollar of revenue that is received by the CSP for a specific end-use customer's load reduction is paid by the LSE of record for that specific end-use customer for that specific day.[12] This market structure was established based on the cost causation principle whereby the LSE of record pays for the load reduction since the LSE would otherwise receive the benefit of additional revenue or lower cost through no action of its own, but rather through the actions of the customer reducing consumption in response to price.[13] This mechanism leaves the LSE

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[12] *See* PJM Operating Agreement, Schedule 1, Section 3.3A; PJM Tariff, Attachment K—Appendix, Section 3.3A.

[13] *See In the Matter of the Commission's Investigation Into Any and All Matters Related to Commission Approval of Participation By Indiana End-use Customers in Demand Response Programs Offered By the Midwest ISO and PJM Interconnection*, Pre-Filed Direct Testimony of Paul M. Sotkiewicz, Ph.D. on Behalf of PJM Interconnection, L.L.C. at 15, Indiana Utility Regulatory Commission Cause No. 43566 (March 5, 2009). (A settlement and accounting mechanism has been set up for the PJM Economic Load Response Program which distributes the wholesale market savings attributable to demand response. In accordance therewith, a LSE will either save purchasing power as a result of its end-use customer's demand response that it can use to serve the customer, or the LSE will now have excess MWhs resulting from the customer's demand response that the LSE can sell in the wholesale market.) While PJM continues to believe that economic load response compensation equal to the LMP minus the generation portion of the retail rates is consistent with the way LMP based customers buy energy and the best alternative for the PJM marketplace, PJM has not repeated the reasoning that supports payment of LMP minus

revenue neutral with respect to the wholesale energy market and thereby does not create incentives to inefficiently hinder demand response or inefficiently encourage demand response.

Accordingly, if demand resources taking service under retail rate structures that do not emulate fixed quantity contracts as described above are directly compensated inappropriately based on LMP, and there is no change in retail market rules that affect participation in wholesale economic load response, then PJM expects that the cost associated with direct payments for demand response allocated to PJM Market Participants will significantly increase in order to ensure the LSE is left revenue neutral in this situation.[14] The increase in cost will likely be driven by: (a) a change in the compensation structure in PJM from compensation based on the difference between the wholesale and retail price to simply the wholesale price[15]; (b) more PJM Market Participants engaging in demand response, and an increase in demand response participation per Market Participant in the market due to the availability of a higher revenue stream; and/or (c) a

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generation because the Commission has taken administrative notice of the record in the PJM proceeding in Docket No. EL09-68-000.

[14] As further explained below, to the extent that implementation of the compensation proposed in this NOPR is delayed to allow state retail markets to realign their rules, the dollar impact may be reduced.

[15] Please note, as PJM previously filed in Docket Nos. EL08-12 and EL09-68, price would be reflective of LMP-G, not LMP—(G+T).

change in the composition of end-use customers that participate in demand response, since end-use customers with retail rates linked to wholesale market energy prices currently have limited opportunities to receive revenue directly from the wholesale market in addition to savings on their retail electricity bill.[16] As noted below, there are a variety of ways that this increased cost (which must be considered in the context of the concomitant increase in demand response resources) can be addressed by the Commission. PJM presents certain options to address this issue of the allocation of those increased costs.

A. Allocation of Direct Payments in which Direct Compensation at LMP is Efficient and Appropriate in the Current PJM Context

Consider the customer taking service under a fixed quantity contract, or any variant discussed above, that engages in demand response. The demand responder has purchased advance energy that it now does not consume and is paid LMP for the energy not consumed. From the perspective of the LSE, it has avoided the need to purchase energy from the wholesale market at LMP to serve the fixed quantity, reducing its costs. If the direct payment made to the demand responder is allocated to the LSE as it is today in PJM, then the avoided cost at LMP is paid

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[16] Under the existing PJM Tariff, a demand response resource that already receives a retail rate based on Real-time wholesale market prices will only receive revenue from the wholesale market when PJM dispatches the demand response resource and the ensuing Real-time market price is less than expected by PJM.

from the LSE to the demand responder leaving the LSE revenue neutral with respect to demand response.

B. Allocation to the LSE of Direct Payments in which Direct Compensation at so-called "LMP-G" is Efficient and Appropriate in the Current PJM Context

Under the retail rate structure where there is no fixed quantity contract and the customer is not billed or charged at the retail rate for the amount of demand response (CBL less the metered load), appropriate compensation as discussed above is at LMP less the generation portion of the retail rate (LMP-G). Using numbers from the previous example will again help illustrate that allocating the direct payment to the LSE leaves it revenue neutral with respect to the wholesale energy market. For a 1 MWh reduction from a customer with a fixed rate of $120/MWh at a LMP of $150/MWh, the direct payment made to the demand responder is $30/MWh. From the LSE's perspective, demand response implies that it can avoid buying power to serve that load saving $150/MWh, but it also loses revenue of $120/MWh because the customer was not metered and billed for the 1 MWh. If the $30/MWh direct payment is allocated to the LSE, as is done today in PJM, the LSE is revenue neutral with respect to the wholesale energy market as the $150/MWh cost savings is offset by a combination of $120/MWh in lost revenue and the allocation of the $30/MWh direct payment made to the demand responder.

C. Options and Issues Regarding the Allocation of Direct Payments When the Compensation is Not Appropriate for the Retail Rate Structure

If the Commission were to enforce demand response compensation at the LMP to the traditional, standard retail rate structure where there is no fixed quantity contract and the customer is not billed or charged at the retail rate for the amount of demand response (CBL less the metered load), then PJM requests clarification on how to allocate to the market the additional costs associated with direct payments for demand response. The allocation of payments made to demand response and generation in the energy market is fundamentally different because a generator is paid based on MWh of energy produced and delivered in the wholesale electricity market, whereas the demand response resource is paid based on energy that is not consumed by the end-use customer in the retail market. In consideration of this challenge, PJM outlines three alternative options for allocating these direct payments to demand response and potential issues with each option.

Option One—Allocate part of the Direct Payments to the Demand Response Customer's LSE and part to all of the LSEs serving the Zone. One allocation approach is to leverage the methodology previously filed by PJM where the LSE of record will receive a direct allocation of direct payments made for the demand response MWh reduction multiplied by the difference between the appropriate wholesale market price and the retail rate, and the cost associated with

the MWh reduction multiplied by the retail rate allocated to all LSE's in the same zone where the load reduction occurred based on a load ratio share.[17] This method was developed to keep the LSE of record[18] revenue neutral directly with respect to the demand response action while allocating the remaining cost to all LSEs within the Zone that are deemed to have "benefited" from the potential impact on LMP of the load reduction.[19] Again, this method does not assume any particular action of the part of the RERRA to allocate cost as deemed appropriate in the retail mar-

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[17] *See* August 26 Supplemental Report, Exhibit A, *Pro Forma* PJM Tariff and Operating Agreement Sheets Redline, Section 3.3A.

[18] Under the existing PJM Tariff, the LSE of record must be maintained for each transaction for each end-user customer along with the appropriate retail rate for each hour of demand response activity. In deregulated retail electricity markets, the LSE of record and associated retail rates may change on a frequent basis.

[19] PJM has recently provided an analysis at the request of the Maryland Public Service Commission showing the reduction in LMP and load expenditures in the BGE and Pepco compared to the allocation of costs associated with direct payments for demand response to load in these zones. The analysis provides upper and lower bounds for the net reductions in load payments to load not engaging in demand response under so-called "Full LMP" compensation as proposed by the Commission. The analysis shows the potential for net reductions in load expenditures to be negative, or equivalently load payments increase under so-called "Full LMP" compensation. *See* PJM Interconnection, L.L.C., *Analysis of Load Payments and Expenditures under Different Demand Response Compensation Schemes*, May 12, 2010, available at http://www.pjm.com/markets-and-operations/demand-response/~/media/markets-ops/dsr/analysis-of-load-payments-and-expenditures.ashx.

ket, and retains the role for PJM to discern retail rates in the wholesale electricity market.

An example of this method can be explored based on a 10 MW reduction for 1 hour, when the applicable real-time wholesale price is $100/MWh and the applicable portion of the retail rate for the specific customer is $50, where LSE 1 is the LSE of record and there are a total of 4 LSEs in the Zone: LSE 1, LSE 2, LSE 3 and LSE 4. This example assumes LSE 1, LSE 2 LSE 3 and LSE 4 all have the same load for the hour when the end-use customer provided the load reduction. Under this method the total cost to allocate is 10 MWh multiplied by $100 or $1,000. LSE 1 would receive a direct cost allocation of $500 (10 MWh multiplied by the difference between the $100 wholesale price the $50 retail price) that keeps it revenue neutral with directly respect the demand response action, plus an indirect cost allocation of $125 (25% load ratio share multiplied by $500), for a total cost of $625. LSE 2, LSE 3 and LSE 4 would each receive a cost allocation of $125 based on their hourly load ratio share. In spite of the intention of keeping the LSE of record revenue neutral, the indirect allocation of extra costs associated with direct payment at LMP makes the LSE financially worse off as a result of demand response and hinders demand response activity.

Option Two—Allocation to All LSEs Within the Zone Impacted by the Demand Response Reduction. A second "uplift" oriented approach allocates all cost associated with demand response in a Zone to all LSEs within that Zone based on a load ratio share. Under

this scenario, the allocation of direct payments is distributed to all LSEs in the Zone assuming the deemed "benefits" of demand response accrue to those LSEs on a proportional basis. This approach greatly simplifies the existing PJM registration and settlement process for all PJM Market Participants, and eliminates the use of retail rates in the cost allocation process. Therefore, PJM would potentially be able to eliminate or significantly reduce the existing LSE review during the Economic Program registration and settlement process since it would no longer be necessary to validate the underlying retail rates.[20] However, the LSE serving the customer engaging in demand response is no longer revenue neutral with respect to demand response. Because the allocation of direct payments is spread out over all LSEs, the LSE of record may have the incentive to inefficiently encourage demand response as cost savings from not serving one MWh of load can be partially retained

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[20] The primary role of the LSE in the registration review process is to: verify that such LSE is the LSE of record, ensure the underlying retail contract type and prices are accurate, verify the existing load currently does not have a contractual obligation with the LSE, and to potentially review whether or not the end-user customer may participate based on a RERRA order, ordinance or resolution. PJM believes all four items performed by the LSE may no longer be necessary since the retail rates and underlying contract would no longer be germane, and the EDC will still perform the role of determining whether the end-user customer may participate based on a RERRA order, ordinance or resolution. The primary role of the LSE in the settlement review process is to ensure the retail rates are accurate, which would no longer be relevant.

while shifting costs to other LSEs in the Zone. Such an outcome would require careful coordination between the RTO and RERRA, and possibly between RERRAs, and may require action on the part of RERRAs that have jurisdiction over LSEs in the same Zone to ensure revenue neutrality for the LSE of record.

An example of this method can be explored based on a 10 MW reduction for 1 hour, when the applicable real-time wholesale price is $100/MWh and the applicable portion of the retail rate for the specific customer is $50, where LSE 1 is the LSE of record and there are a total of 4 LSEs in the Zone: LSE 1, LSE 2, LSE 3 and LSE 4. This example assumes LSE 1, LSE 2 LSE 3 and LSE 4 all have the same load for the hour when the end-use customer provided the load reduction. Under this method the total cost to allocate is the same as above, or 10 MWh multiplied by $100 or $1,000. Here, LSE 1, LSE 2, LSE 3 and LSE 4 would each receive a cost allocation of $250 based on their hourly load ratio share. With the demand response, LSE 1 avoids a cost of $500 (10 MWh multiplied by $100/MWh of avoided cost to serve the load less the lost revenue of 10 MWh multiplied by $50/MWh), but is only allocated $250 of direct payment. The implication is that LSE 1 is financially better off with the demand response and would like to inefficiently encourage more demand response to increase its own financial gain through the shifting of costs to other LSEs.

Option Three—Allocate to the LSE of Record. A third cost allocation approach is to have the LSE of record pay for the demand response. This assumes that the deemed "full benefit" of demand response is only received by the LSE of record, and that demand response does not impact other LSEs within the Zone or across the RTO.[21] PJM would need to continue to maintain the LSE of record for demand response by end-use customer for the registration and settlement process to implement this approach. This allocation method does not leave the LSE revenue neutral, and by allocating all direct payments to the LSE of record, the LSE now has the incentive to deter demand response because demand response results in decreased revenues from a wholesale energy market perspective. As with Option Two, this outcome would require careful coordination between the RTO and RERRA, and possibly between RERRAs, and may require action on the part of RERRAs that have jurisdiction over LSEs in the same Zone to ensure revenue neutrality for the LSE of record.

Under this method, based on a 10 MW reduction for 1 hour, when the applicable real-time wholesale price is $100/MWh and the applicable portion of the retail rate for the specific customer is $50, where LSE 1 is the LSE of record and there are a total of 4 LSEs in the Zone (LSE 1, LSE 2, LSE 3 and LSE 4), the total cost of $1,000 would simply be allocated in its entirety to LSE 1. However, the avoided cost on net for LSE

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[21] *See supra* note 19.

1 is $500, and allocating the $1000 in direct payments will leave LSE 1 worse off financially by $500 relative to having no demand response.

The increase in compensation to the full wholesale price, if applied inappropriately, may without action and coordination at the retail level, distort market incentives and result in potential cost shifting among market participants.[22] As discussed above, PJM has outlined some alternative options to allocate this cost, and respectfully requests that the Commission include the allocation of direct compensation payments as part of the policy discussion regarding the NOPR's compensation for demand resources.

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[22] *See PJM Industrial Customer coalition v. PJM Interconnection, L.L.C.*, Answer of PJM Interconnection, L.L.C. to Compliant of PJM Industrial Customer Coalition at 9, Docket No. EL08-12-000 (December 6, 2007). ("[T]he proposed perpetual extra incentive above and beyond the true economically efficient (LMP minus retail rate purchase cost) price signals could skew market signals, resulting in inefficient and ultimately more expensive energy alternatives in the long run. If economic demand side response becomes the sizable and important resource all hope for, perpetually providing this type of extra out of market revenue payment to demand side responders effectively favors the development of demand side resources over all other alternatives. While encouraging development of more economic demand side response may be beneficial in the short run, in the long run continued incentives may well stifle development of newer, more efficient alternatives by artificially lowering the price all other resources are paid.").

D. Demand Response Administration

Compensation for economic load response equal to the LMP, regardless of retail rate structure, could significantly reduce the administrative burden for all PJM Market Participants during both the registration and settlement review process, but if applied inappropriately may reduce market efficiency and create unintended incentives and cost shifting as described above. If cost allocation does not require the LSE of record to be identified or the identification of a specific retail rate, this will simplify the existing administrative process and remove PJM from of the role of documenting and interpreting retail rates which are the exclusive province of the RERRAs.[23] Moreover, a CSP would no longer be required to determine the LSE of record, interpret and determine the retail rate and provide such information to PJM. Further, PJM would no longer be in the position of providing this information back to the LSE of record, and of resolving issues or disputes between the CSP and LSE around the specific determinations, including those of retail rates.

Additionally, the Commission may need to reconsider or review previously filed and/or approved PJM Tariff and Operating Agreement revisions. For example, PJM recently provided the Commission with a

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[23] The EDCs and LSEs are entities jurisdictional to the RERRAs. PJM (which is a public utility itself, regulated at the wholesale level, and not a regulator) should not be in a position to interpret a RERRA approved tariff or commercial contract for competitive retail service.

detailed description of the normal operation and settlement review process and proposed Tariff and Operating Agreement language setting forth the associated criteria.[24] The normal operation review process verifies that registered sites take explicit actions to reduce load in response to PJM market price signals and do not represent load reductions based the difference between the CBL and meter load for normal business operations.[25] The settlement review applied by PJM to economic load response settlements includes: (1) submission of a settlement for self scheduled energy in the Real-time Energy Market where only some of the self scheduled hours have been included in the daily settlement submission; (2) daily settlement with an estimated value less than Five U.S. Dollars ($5.00); or (3) daily settlement has a significant number of uneconomic hours.[26]

In this case, the Commission could conclude that a LMP floor, which is currently part of ISO New England's market design, should limit economic load response participation to mitigate potential market integrity issues that may arise. This is a simplistic approach which will focus economic demand response

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[24] *See PJM Interconnection, L.L.C.*, Compliance Filing at 7, Docket No. ER09-1063 (March 18, 2010).

[25] *Id.*

[26] *Id.* Uneconomic means that the load reductions were performed when the applicable portion of the retail rate was higher than the wholesale price, and therefore the reductions are inappropriate market behavior.

activity to periods when only higher cost generation is available.

IV. Implications for the Retail Market

A. Coordination Between the Commission and RERRAs

The integration of the wholesale and retail electricity markets continues to challenge both wholesale and retail market designers and administrators. This is especially challenging in a large wholesale marketplace like PJM's, which includes all or parts of 13 states plus the District of Columbia. PJM believes that the Commission should carefully consider all of the various competing impacts of compensation equal to LMP at the wholesale level on retail markets. It is reasonable to assume that each RERRA in PJM will re-examine the impact of load reduction based on wholesale compensation equal to the LMP, including cost allocation, on the LSEs subject to its jurisdiction, and potentially re-align retail market rules affecting economic load response participation. Because of the diversity of the RERRAs within PJM's footprint and the issues delineated above, the Commission may wish to consider a phase-in period for implementation of the final rulemaking, regardless of its form, which would accommodate the need for RERRAs to review and potentially align retail market rules. Such a phase-in period would establish the details of the final rule, but defer the implementation date so as to allow individual RERRAs time to take the necessary action to account at the retail level for the wholesale compensation stipulated by the Commission.

PJM strives to treat generation and demand response resources symmetrically, meaning that PJM will dispatch the least cost resource—generation or demand response—that will maintain the balance of supply and demand in the Real-time Energy Market. One distinction between energy market participation by generation resources and demand resources, however, which RERRA's may consider, should be noted. Generation resources provide PJM with a meter reading that verifies the MWh of energy production delivered by them into the energy market. Demand response resources, however, do not interact directly with PJM unless they are a PJM Member acting as their own CSP. Rather, demand response resources provide usage reduction based on CBLs through CSPs that aggregate the load reduction capability of end-use customer sites and provide them to the wholesale energy market.

One CSP avers in an affidavit filed earlier in this proceeding that " when a DR provider participates in the market they are engaging in two separate transactions that must remain separate. The first transaction is between the DR provider and the RTO wherein the DR provider sells in curtailments at LMP. The second transaction is between the DR provider as a customer of an LSE serving the non-curtailed load. The price that the DR provider pays for this can either be based on LMP, a negotiated price or tariff."[27] Clearly the RERRA will consider and influence

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[27] *PJM Interconnection, L.L.C.*, Motion for Leave to Answer and Answer of Demand Response Supporters, Reply Affidavit of Allen

the price paid by the demand response provider to jurisdictional LSEs. PJM anticipates that RERRA and LSE comments submitted in this docket will reflect all of the retail reactions described below and variations in-between. Likely RERRA reactions to economic load response compensation equal to LMP include:

i) Complete Review and Acceptance

A RERRA in PJM may conclude that wholesale compensation for economic load response equal to the LMP is appropriate and does not distort market prices. In short, the RERRA may decide, in its discretion, that the assignment of costs to the LSE under one of the options outlined above is acceptable due to their relative size, various other state policies or individual utility regulatory circumstances such as the existence of a rate freeze. Depending on the allocation of cost associated with compensation equal to LMP, the RERRA might acquiesce to uplift charges by PJM to jurisdictional LSEs and leave retail market rules unchanged.

ii) Complete Review and Limited Acceptance

A RERRA in PJM may conclude that wholesale compensation for economic load response equal to the LMP is inappropriate and distorts wholesale and retail market prices, but that the distortion is acceptable on a temporary basis to enable demand response resourc-

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M. Freifeld on Behalf of Demand Response Supporters at 8, Docket No. EL09-68-000 (November 12, 2009).

es to be developed and offered into the wholesale market or as a needed bridge to the retail deployment of advanced meters, meter data management systems, dynamic retail prices that are linked to wholesale prices or system conditions and automated controls that implement the price/quantity decisions of end-user customers. The latter is also referred to as PRD.

iii) Rejection and Revision of Retail Market Rules or Opt Out

A RERRA in PJM may conclude that wholesale compensation for economic load response equal to the LMP is inappropriate and distorts wholesale and retail market prices. In this event, the RERRA will have a number of options for redressing what it deems to be inappropriate wholesale market design or removing price distortions imposed by wholesale market design, including the following: a) revising retail tariffs to charge the end-use customer for the generation and transmission portion of the retail rate for the quantity curtailed,[28] or b) adopting an order, ordinance or resolution that prohibits end-use customers served by jurisdictional LSEs from participating in some or all of the opportunities for demand resources to participate in the wholesale market as supply side resources. The prohibition devised by RERRAs with jurisdiction over smaller distributors that deliver 4 million MWh or fewer per annum may entail the revocation of previously provided permission to participate in some or all

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[28] *See supra* note 15.

of the wholesale market opportunities for demand resources.

B. Competitive Load Serving Entities

There are a number of restructured states in PJM's footprint, including Ohio, Pennsylvania, Maryland, Delaware and New Jersey, which permit direct retail electricity sales by licensed competitive LSEs. While they oversee the format of contracts offered by competitive LSEs, particularly for residential customers, authorities in restructured states may not review and approve the prices and other terms of service agreed to by competitive LSEs and the end-use customers they serve. Rather, these matters may be the subject of negotiated private contracts between the competitive supplier of electricity and the end-use customer. PJM anticipates that competitive LSEs, like RERRAs, will review and perhaps revise terms and conditions of retail electricity sales when economic load response compensation equals the LMP in all hours on a permanent basis.

Competitive LSEs are likely to be particularly sensitive to the cost allocation method used by PJM to recover direct compensation paid to CSPs as described above if such allocation does not leave the LSE revenue neutral with respect to the wholesale energy market. For example, a competitive LSE that manages a block of energy for an end-use customer by selling unused energy in the Real-time Energy Market, and crediting the end-use customer's account with the proceeds, may revise these contract terms if PJM's Tariff directs PJM to charge the end-use customer's LSE for

the LMP compensation paid by PJM to the CSP. In this example, presumably it is not the intention of either the buyer or the seller that the competitive LSE would credit the end-use customer's account with Real-time Energy Market proceeds ***and*** pay charges from PJM for the same MWhs of unused energy.

Like the RERRA, the competitive LSE will have a range of options to deal with related to economic demand response compensation equal to LMP. Like the RERRA, the competitive LSE could revise the contract terms to ensure that there is no double payment for unused energy first through a credit to the end-use customer's account and then again through payment of a charge imposed by PJM to collect compensation owed to the CSP. Like the RERRA, the competitive LSE could also revise the contract terms to prohibit demand response participation in the PJM wholesale markets outright or through any CSP other than the competitive LSE.

V. Implications of LMP Compensation for Wholesale and Retail Integration of Price Responsive Demand ("PRD")

A. Savings versus Savings + LMP

Prior to issuing the Demand Response Compensation NOPR, the Commission had expressed interest in and support for the integration of PRD in wholesale and retail markets.[29] Compensation for economic load

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[29] *See PJM Interconnection, L.L.C.*, Order on Compliance Filing at P 93, Docket Nos. ER09-1063-000, -001 (December 18, 2009).

response equal to the LMP impacts the symmetry between the supply side and load side of the market where changes in energy usage in response to dynamic rates or PRD will inform the price/quantity data for each location that LSEs provide to PJM. In other words, LSEs implementing PRD will account for each MW of reduction in response to price at a specific location and report the amount to PJM. PJM will then reflect each MW of reduction related to the LMP on a one-for-one basis when scheduling both Day-ahead and in Real-time. The savings to the end-use customer who reduced usage in response to a dynamic rate will accrue to that customer on a one-for-one basis, resulting in savings at least equal to the generation portion of the retail rate, related in some way to wholesale market prices, for each kW of usage reduced.

The end-use customer participating through a CSP as a supply side resource, however, will not only save the generation portion of its retail rate but will also receive a portion of the LMP paid by PJM to the CSP as would be the case under the Commission's proposal. The clear PRD benefit of using the meter to measure the actual usage at each price, as opposed to calculating and administering the CBL (estimating what the customer otherwise would have used) and receiving compensation through avoided cost savings, could easily be outweighed by the financial preference that inappropriate application of LMP compensation pro-

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The Commission ordered PJM to provide periodic updates regarding the integration of PRD.

vides economic load response participants, and have the unintended consequence of retarding the expansion of PRD.[30]

B. Compensation Proposal Impact on PRD Retail Integration

LSEs and RERRAs that are integrating PRD in the retail market face significant challenges, including, but not limited to, advanced metering infrastructure business cases, stimulus funding requirements imposed by the U.S. Department of Energy, development of and timelines for offering voluntary or mandatory dynamic rates, customer education plans, contingency plans for unmet customer expectations, decoupling of distribution rates, and plans for buying wholesale electricity. The Commission's proposal to pay economic load response LMP regardless of retail rate structure, if implemented in the final rule, adds one more complexity that LSEs and RERRAs integrating PRD must address. For this reason, PJM supports a phased-in compensation solution in the final rule for economic load response, as noted above. Moreover, the affected LSEs and RERRAs may react to the Commission proposed LMP compensation paid for economic load response by adjusting retail rate design or prohibiting jurisdictional end-use customers from participating in the energy, capacity and ancil-

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[30] *See* Paul Centolella and Andrew Ott, *The Integration of Price Responsive Demand into PJM Wholesale Power Markets and System Operations* at note 2 (March 9, 2009) (PRD as the third generation of demand response), available at: http://www.hks.harvard .edu/hepg/Papers/2009/Centolella%20%20Ott%20PJM%20PRD%2003092009.pdf

lary services wholesale market opportunities available to demand response resources.

VI. Conclusion

PJM recognizes the Commission's efforts to address the complex question of demand response compensation, which PJM believes inherently involves the relationship between wholesale rates, retail rates and ratemaking, and the extent and nature of the retail obligation to serve by the LSEs. PJM has attempted to provide constructive solutions and options for the Commission's consideration so as to allow for thorough consideration of any rule on this difficult subject. As noted herein, the PJM markets accommodate a wide range of retail markets from fully regulated and vertically integrated to restructured and completely unbundled, and the Commission's proposal to pay compensation equal to LMP regardless of retail rate structure raises significant issues affecting the wholesale market and the retail market, including the integration of PRD. Compensating economic demand response based on LMP is appropriate and efficient under some retail rate structures, but may not be appropriate or efficient for other retail rate structures, and may result in an increase or decrease in the demand resources participating, depending on the outcome of RERRA review and reaction. Regardless of the form of the final rule, PJM recommends that the Commission include a two year phase-in period to give the RERRAs time to review and react to any changes in compensation for economic load response set forth in the final rule. Additionally, the two year period will give the

Commission time to address the allocation of direct payments to LSEs and market integrity issues at the wholesale level, as discussed above.

Respectfully submitted,

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Dated: May 13, 2010

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May 13, 2010

Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

RE: Demand Response Compensation in Organized Wholesale Markets, Docket No. RM10-17

Dear Mr. Chairman and Commissioners:

The Delaware Public Service Commission ("DEPSC") appreciates the opportunity to submit these limited comments in response to the Commission's Notice of Proposed Rulemaking ("NOPR") regarding Demand Response Compensation in Organized Wholesale Markets (RM10-17). First, the DEPSC agrees with the observations made in the NOPR that there are considerable benefits coinciding with reductions in electric demand, and that entities

that are able to respond to the real cost of energy should be fairly compensated for so doing. To that end, the electric distribution company (the "Company") under the DEPSC's jurisdictional authority is in the process of installing advance metering infrastructure throughout its entire Delaware service territory, which will be fully deployed by the end of 2011. Concurrently, the DEPSC has an open docket that, when concluded, may effectively eliminate the linkage between the Company's revenue and its electric sales. By removing this linkage, the Company will become less sensitive to fluctuations in demand, while the disincentives inherent in promoting the benefits of energy efficiency and conservation to its customers will be greatly diminished. Moreover, a request was recently filed by the Company to implement dynamic pricing for its customers which, if approved, will allow all customers to respond to real-time increases in energy prices by reducing or shifting their consumption.

The DEPSC, at this time, will not advocate a position regarding the Commission's proposal as put forth in the NOPR. However, because of the ongoing proceedings the DEPSC discussed previously, the DEPSC respectfully reminds the Commission that changes to demand response compensation at the wholesale level may create unintended consequences for the success of state retail programs that are either in effect currently, or will become effective in the near future.

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UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. RM10-17-000

DEMAND RESPONSE COMPENSATION IN ORGANIZED
WHOLESALE ENERGY MARKETS

COMMENTS OF VIRIDITY ENERGY, INC.

Viridity Energy joins in the comments submitted by Demand Response Supporters, and files these comments as well in order to expand upon some of the Demand Response Supporters' answers to the questions posed by the Commission.

I. Background

a. History

Since the 1970s, government's approach to regulated industries has relied more on market mechanisms and less on cost of service regulation, to deliver benefits to consumers.

In several of the industries the transition to markets was relatively rapid and was marked by a single major event or Order that hastened the transition. Order No. 636 mandating open access to gas transmission facilities and Judge Greene's Modification of Final Judgment in the telecommunications field are examples. This evolution delivered significant consumer benefits in these industries, despite the forecasts of

doom and unintended consequences by incumbent interests.

Such pessimistic forecasts are to be expected. The evolution toward greater reliance on markets is never easy or uncontroversial. Incumbent interests are often motivated to resist innovation which threatens the status quo. Multiple arguments are raised about why the innovation will not work—reliability will be threatened, uneconomic results will obtain, etc.

Invariably, these arguments are shown over time to have been wrong—and the innovation brought to the market by new entrants and new business models proves to be in the public interest. So it will be with advances in demand response (hereinafter dynamic, price responsive load control) and distributed resources—if the Commission continues on the path it has begun. Continuing on that path will enable the Commission, its market rules, and the ISOs and RTOs to keep pace with the evolution of the markets.

Unlike the gas transmission and telecommunications industries, the electricity industry experienced no single transforming event to bring about the transition to market mechanisms. Instead, the transition is being accomplished more slowly, step by incremental step to improve the functioning and competitiveness of the markets. Steps in the evolution have included the creation of qualifying facilities under PURPA; the development of an independent power producer industry; the advent of open access transmission; the creation of Independent System Operators and Regional Transmission Organizations; the creation of

day-ahead and real-time energy markets; the development of markets for ancillary services; and the creation of hedging tools such as Financial Transmission Rights.

These steps have encouraged participation by non-traditional market entrants, focusing on the supply side of the market. With the Commission's recent Strategic Plan, Order 719, and now the NOPR, the focus has expanded to encompass the demand side, by encouraging and empowering active load management by customers.

b. The New Role of Load

That expanded focus has coincided with an expanded ability and willingness of customers to manage their load. As stated above, the electric industry has traditionally viewed the market as divided into two entirely separate and distinct segments—supply and demand. The industry has treated supply as a variable element which adjusts as necessary to satisfy demand. And the industry has viewed demand as a given—a factor that cannot and does not change in response to price signals.

This view of the interaction between supply and demand is no longer accurate. The interaction between customers and the grid is now far more complex than it has ever been.

The grid itself is more complex in that there are many more resources to be controlled. The interaction between customers and the grid is more complex, because customers may desire to reduce or shift con-

sumption in response to price signals. At the same time, communications technology, software technologies and distributed generation and storage resources are providing customers with a meaningful opportunity to manage price and reliability in the market. Customers no longer serve only as passive buyers of power; now, customers can be active market participants offering flexible load into the markets. Customers are installing increasing quantities of distributed resources and storage devices which can be dispatched when market conditions and rules make it economically sensible to do so. And increasing amounts of intermittent renewable resources present their own new challenges to operation of the grid.

With active customer participation, the grid can function as a more complex, but more efficient, network which uses the full opportunities provided by distributed technologies and customer controlled load to achieve reliability at the lowest possible cost. The increasing participation by customers and renewables in the market creates a more complex task for the grid operator in which all of these new resources—customer resources—must be dispatched along with the traditional supply side resources. At the same time, the grid operator has all of these competing resources potentially available for dispatch, and the ability to choose among them to balance the grid. The proposed rule begins the process of integrating these diverse resources by valuing all of them at the market price.

The Commission's Notice of Proposed Rulemaking raises several key issues that will arise along that path. Viridity's supplemental responses to those issues follow.

Issue: **The need to compensate demand response acting as a resource in organized wholesale energy markets, including whether current compensation for demand response providers is adequately procuring demand response**

a. Active load management is virtually nonexistent under the current compensation rules—and will stay that way without adequate compensation.

Thus far, dynamic, price responsive load control has achieved only minimal penetration into the wholesale energy market. It still faces significant barriers, which the Commission has recognized and made initial steps to overcome.[1] The near absence of this service from the energy markets (as opposed to the capacity markets) is powerful empirical proof that the current level of compensation is inadequate—especially in markets that start with a market-based level of compensation and then reduce it by the generation portion of a customer's retail rate ("LMP-G").

The record establishes that sufficient compensation will call forth substantial amounts of demand response and that inadequate compensation will not. By way of example, the Commission has ordered comparable

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[1] NOPR, Paragraph 5.

compensation of demand resources in the capacity markets. As a result, in both PJM and ISO NE, demand resources constitute a substantial portion of the resources clearing in those capacity markets. On the other hand, comparable compensation in the energy markets has not been the rule; as a result, demand response participation in these markets is de minimis. Further, when compensation in PJM was reduced from the LMP level, the quantity of demand response offered into the market declined.[2]

b. Sufficient compensation will lead customers to provide demand response.

Despite the attention now being paid to demand response, it is in fact a nascent industry. For several reasons, efficient expanded deployment of demand response depends on sufficient compensation.

Unlike a generating company, whose primary mission is to generate and supply electricity, a customer contemplating demand response knows that its primary mission is different. A supermarket chain is in the business of selling groceries; a pharmaceutical plant is in the business of producing medicines; a university campus is in the business of educating students. These customers have made capital investments and implemented operational procedures with the goal of being successful in their core business.

Customers can enhance their ability to actively control their load from a variety of resources, at a cost.

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[2] *See* Freifeld Affidavit, pages 17-18, Case No. EL09-68-000.

Those customers can make the capital investments and operational changes needed to participate in the energy market with demand response. The necessary investments may include automated load curtailment systems, building energy management systems, energy storage, and other technologies to enable active price responsive load control. Examples of the operational changes include rescheduling or curtailing production, or allowing indoor temperatures to rise above what had previously been considered comfortable levels.

However, the investments needed to provide demand response must compete with other investment opportunities that can advance the core business—such as the expansion of a store, the purchase of machinery and equipment needed to produce a new product, or the construction of a new dormitory to address a housing shortage. The operational changes must not unduly harm the core business—by driving customers away from the store because of higher temperatures, by excessively sacrificing production, or by imposing discomfort on prospective donors visiting the school.

Customers will make the necessary investments and changes if they expect to be in the market when it is of value to the grid and to them, and expect that they will be adequately compensated. Just as in other areas of economic activity, the decision to take these actions depends on the prospect of sufficient compensation to make them worthwhile. Prospective

investors in generation and transmission behave in the same way.[3]

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[3] *See, e.g., PJM Interconnection, L.L.C.*, Order Denying Rehearing and Approving Settlement Subject to Conditions, 117 FERC ¶ 61,331 (December 22, 2006). "As the energy needs of participants in competitive markets subject to our jurisdiction continue to grow, the Commission must ensure just and reasonable rates by requiring that the energy supply continue to meet these growing needs. Specifically, the Commission must approve market designs and rate policies that elicit sufficient investment in energy, transmission, and demand response" (paragraph 1); "the Commission found that as a result of a combination of factors, PJM's existing market rules are unjust and unreasonable, because they fail to set prices adequate to ensure sufficient resources. . . . PJM also contends that reliability problems are likely to extend to other parts of PJM in the near future, despite existing adequate supplies in those areas, because much of PJM's generation fleet is very old (and thus, may soon be retired), and because current market revenues are likely to be insufficient to sustain continued and future investment" (paragraph 3); "We agree that the Variable Resource Requirement construct alone is not sufficient to provide appropriate incentives for efficient investment decisions—whether new entry or a retirement decision is at stake. However, revenues from a well-designed and reliable capacity market are one important element supporting efficient private investment" (paragraph 77).

Issue: **Whether a reduction in consumption is comparable to an increase in electricity production for the purposes of balancing supply and demand.**

a. A reduction in consumption is comparable to an increase in supply.

The principal responsibility of the grid operator is to maintain the grid in balance—and to do so in an independent and neutral way. Electricity is not a commodity we can hold in our hands, store in our walls for later use or keep in a warehouse for later distribution.[4]

Balance can be maintained by a decrement of load or an increment of supply. A reduction in consumption will physically balance supply and demand just as effectively as will an increase in supply. By way of example, if a generating unit trips off, and the grid operator has the choice of dispatching a replacement generator or of dispatching controllable load to restore the balance, the operator should choose the least-cost alternative. Unlike any other commodity, once electrons are produced they must immediately be consumed and converted into something useful like light or cooling, or the entire integrated electric system will fail.

Balance can be maintained by a decrement of load or an increment of supply. A reduction in consumption will phys-

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[4] Electricity cannot be stored. However, energy can be stored in a different form for later conversion into electricity.

ically balance supply and demand just as effectively as will an increase in supply. By way of example, if a generating unit trips off, and the grid operator has the choice of dispatching a replacement generator or of dispatching controllable load to restore the balance, the operator should choose the least-cost alternative.

In the context of this proceeding, independence and neutrality require that reductions in load and increases in supply be evaluated and treated equally. And, as discussed below with respect to comparability of compensation, either resource should be paid the competitively determined clearing price.

b. Misleading arguments are often advanced to imply that a reduction in demand is not comparable to an increase in supply.

Opponents of the Commission's proposal are likely to offer a number of arguments that a reduction in consumption is not comparable to an increase in production. Those arguments generally fall into one of these categories:

1. *Selectively evaluating economic benefits to the curtailing customer outside the wholesale energy market.* An example that considers benefits other than wholesale market compensation to the end-use customer providing demand response, but considers no such outside benefits to generators, is misleading. Most commonly, the evaluation includes the end-use customer's savings on retail costs. Opponents of the proposed rule refer to this as "double compensation." However, these parties do not apply the same standard

to generation. They do not suggest, for example, that the Commission tailor energy market compensation for a nuclear generator to that generator's costs. They do not suggest that the Commission investigate the profitability of nuclear or coal plants that are paid the gas-driven clearing price.

While the opponents of the rule urge the Commission to investigate the savings achieved by certain customers they studiously avoid consideration of any benefits to generators, including government subsidies and tax benefits. Examples of those benefits include tax credits for kilowatt-hours produced by generators combusting municipal solid waste and other specified generators under Section 45(a) of the Internal Revenue Code ("IRC"), reductions in fuel costs for generators combusting refined coal due to tax credits under Section 45(e)(8) of the IRC, and the value of renewable energy certificates earned by eligible generators under state renewable portfolio standards. All of these benefits have corresponding societal costs which opponents of the Commission's proposal exclude from their illustrative examples.

The "double compensation" argument depends on an investigation of the microeconomic circumstances of a particular customer—an investigation that is never undertaken to reduce generating resources' compensation from the energy market. If such an investigation were to be applied to generators' or demand resources' compensation in the energy market, it would undermine the basic market rule of an offer-based LMP. The argument is simply a distraction from the

significant macroeconomic benefits that active load control brings to all customers.

2. *The "billing unit" distinction.* Opponents of the rule also argue that demand response is not comparable to generation because there is no "billing unit" issue associated with generation. This factor does not in any way represent a challenge to the operational equivalence of demand response and generation in terms of balancing load and supply, as discussed above in detail. The two resources provide the same service and are comparable. The "billing unit" issue is an allocation issue only. And as the Commission is aware there are means available for addressing the allocation issue if the Commission believes the issue should be considered. These means generally involve charging customers for the cost of demand response (either by including the cost in the settlement or via uplift) while insuring that the total cost to customers is still less than it would be absent demand response participation in the market. These twin goals can be accomplished via a dynamic threshold or a properly developed static threshold.

3. *Uplift.* Similarly, opponents of the proposed rule argue that demand response and generation are not comparable because the "billing unit" issue may require some form of uplift to keep LSEs whole. This argument is wrong on several counts. Again, this factor does not in any way represent a challenge to the operational equivalence of demand response and generation in terms of balancing load and supply, as discussed above in detail. The two resources provide the

same service and are comparable. Furthermore, RTO rate structures are rife with uplift charges currently, which fund needed activities; customers already pay uplift charges such as Operating Reserves; Reactive Power; Blackstart; Market Monitoring Units; State PUC operations cost such as for OPSI or OMS; and reliability operations such as for NERC and RFC. The possibility of an uplift related to demand response establishes no real difference between generation and demand response. The fact that demand response compensation may include an element to account for billing unit issues does not in any way suggest that demand response is not comparable to generation.

c. The increasingly greater diversity of resources on the grid makes balancing the grid more challenging—making it necessary to utilize fully the resources available for balance.

The application of security-constrained economic dispatch was relatively simple when demand was primarily seen as inelastic and the only possible response to changes was the incremental or decremental change of output of a generator. In such a market the demand curve and associated supply curve could be easily constructed as shown in various RTO training manuals describing the construction of LMP.

In that simpler world, grid operators had fewer tools available to keep the grid in balance. Today, a much wider array of tools is available to maintain the grid in balance—dispatchable and non-dispatchable, on the distribution grid or behind the meter, power producing, storage or load managing.

That wider array becomes even more important as a myriad of new resources will have to be integrated onto the grid. Wind, solar and even certain forms of hydro generation are dependent on non-controllable events and thus are not truly dispatchable but instead are treated as "non-controllable load on the grid" in the sense that they are price takers and increases and decreases in wind and solar outputs must be matched by either opposite increases or decreases in the output of controllable generation—or storage or flexible load can be used to ensure continued grid balance. Similar challenges arise as conventional generating resources continue to operate.

For example, certain base load generating units have strict operating parameters and a minimum generation requirement. It has long been recognized that it is not reasonable to decrease the output of these below minimum generation due to safety and operational concerns. Consequently, these units will frequently be dispatched in cost-based markets even if their marginal cost of operations is higher than an alternative.

The Commission has correctly asked whether load and supply should be treated comparably in the markets. Answering this question depends on understanding the complexity of today's grid and market operations, and the reality of independent and neutral grid operations. As noted, when operating a grid it is essential first that supply and demand remain in balance. The ability to create an efficient and reliable

grid requires the operator to have sufficient resources that can be controlled to achieve this balance.

On the supply side of the equation, resources that can be dispatched typically have operational costs that have to be recovered in the dispatch price. This includes storage resources which will have an opportunity cost associated with their dispatch. Non-dispatchable renewable resources are generally price takers and consequently will always be paid the prevailing clearing price.

On the load side of the balancing equation some loads will be relatively inflexible and uncontrollable. Other forms of load can be controlled in response to price. This control can occur by switching the time of consumption or the form of supply from grid based to non-grid based resources. Flexible and controllable load can be relied on by operators to keep the grid in balance and can be used as an integral part of the secure dispatch.

When operating in accordance with the principles of security-constrained economic dispatch, a neutral and fair operator should be operationally indifferent as to whether achieving grid balance is achieved by incrementing generation or decrementing load that is offered to balance supply and demand. All other things being equal, the question for the operator is whether the decrement in demand or the increment in generation achieves the goal of a balanced grid at the lowest price.

Issue: **Whether demand response providers and generators should receive comparable compensation.**

For the reasons discussed below, the locational marginal price of energy is the appropriate measure for establishing the value of energy in the markets—regardless of whether a supply resource or a demand resource is contributing to the balance between supply and demand. In either case, the services provided to the grid are comparable. Comparable services should be compensated comparably. To do otherwise is discriminatory. Furthermore, the presence of demand resources in the energy market provides additional benefits to all customers—benefits that are comparable to what is achieved when less expensive generation enters the market.

a. Supply resources and demand resources provide comparable services in keeping the grid in balance.

There is a fundamental difference between electricity and other industries. In no other industry do we demand an absolute, continuous, *instantaneous* physical balance between demand and supply. But in the electric industry an imbalance can threaten the delivery of the service to each and every customer—outages can and do occur because of imbalances.

RTO operations therefore have as their primary goal the instantaneous balancing of load and supply at the minimum possible price. Security constrained economic dispatch is the principal tool used to achieve this objective. Load curtailment, properly managed,

will have a predictable response to given price signals; it can be dispatched pursuant to a pre-set schedule, such as a cleared day-ahead commitment schedule. Demand response can be a dynamic, but predictable, part of the grid operator's tool box for maintaining the balance between load and supply, at the lowest possible price consistent with reliable operations. When an electric customer curtails usage, it helps to insure the reliable supply of electricity at that point in time. It provides a service to the grid and to all other customers.

The RTO is pricing the next kW to keep the grid in balance. Either load or generation is a controllable resource that can be used, based on appropriate price signals and compensation, to keep the grid in balance. The ability of load and the ability of generation to respond—to be dispatched—have been proven. The service that a customer supplies when it removes MWs from the grid is just as valuable as a generator injecting MWs. A decrement of demand has the same market value as an increment of supply.

b. Comparable services should be compensated comparably.

Customers who provide a decrement of demand to keep the grid in balance, and suppliers who provide an increment of supply to serve the same purpose, should be compensated comparably for those comparable services.

Comparable treatment for supply and demand on the grid is consistent with the principle that generally

—and even more in a smart grid environment—supply and demand are both available as resources to maintain secure, reliable and efficient grid operations. As noted, security constrained economic dispatch of the integrated electric grid is the standard protocol for grid operations in both market and non-market regions. Regulatory requirements and reliability protocols require system operators to dispatch resources so as to meet demand in a manner that ensures grid and operational reliability—but at the least cost, be it in a non-market regime or a bid based regime, via security constrained economic dispatch.

The energy markets pay non-dispatchable, non-price responsive generation (run-of-river hydro, for example) comparably to dispatchable, price responsive generation (coal fired, gas fired). No logic supports paying price responsive load substantially less than non-price responsive, non-dispatchable generation. A fair implementation of the Commission's comparability standard requires an acknowledgment that price responsive load is entitled to the same wholesale compensation as both price responsive generation and non-price responsive generation.

c. The locational marginal price ("LMP") of energy sets the right level of compensation for an increment of supply and for a decrement of load.

The compensation of all supply and demand resources at the marginal cost is integral to the design and operation of the organized wholesale electric markets. Similarly, the use of security constrained economic dispatch is a cornerstone of operations. As the

Commission has recognized, the locational marginal price of energy is the appropriate clearing price for establishing the value of energy in the markets.

There is only one comparable, readily identifiable, competitively determined value for that service—LMP. Just as an increment of supply is paid LMP, the decrement of load which displaces a higher priced supply source should also be paid LMP. The decrement of load has the same value to the grid as the increment of supply. LMP reflects the least expensive means available for maintaining that balance between load and supply.

Under the Commission's LMP market design, it has long been established that efficient and fair market design requires that all generators participating in the markets are paid the market clearing price regardless of their costs, whether they are a price taker or can even respond to price. Thus, all generators regardless of cost and their ability to respond to price, benefit from increases in demand and associated increases in the locational marginal price.

Demand that is not flexible or price sensitive will increase the supply requirements on the grid to maintain balance, (and hence the marginal clearing price). But flexible and price responsive demands that can reduce the requirements needed for balance, have the effect of reducing the marginal price of achieving a reliable and balanced grid. Consequently the failure of the market to comparably pay for flexible demand reductions in response to dynamic price signals constitutes a discriminatory bias against price responsive

load participation. The failure to pay flexible load commensurately with the value that it provides to other customers (as discussed below) will yield inefficient grid and market operations to the detriment of ultimate consumers, in the form of prices that are higher than they need be.

In summary, the service provided by a customer curtailing load has the same economic value as a generator increasing its output. The services are comparable and they should receive comparable compensation—LMP. All resources that can be dispatched to provide the necessary balance should be paid the bid-based clearing price. The suggestion that generation should be paid this price but that dynamic, price responsive load should not is discriminatory. Such discrimination between resources that provide the same value to the market is inconsistent with the Federal Power Act's anti-discrimination provisions.

The market has one competitively determined, prevailing price for the service, LMP. We respectfully suggest that the burden is on those who suggest a different level of compensation for dynamic load control, to establish that a different level of compensation is comparable, given the comparability of the value provided to the wholesale grid.

Finally, the record establishes that sufficient compensation will call forth substantial amounts of demand response and that compensation significantly short of LMP will not. We respectfully suggest that those who assert that LMP-G is adequate compensa-

tion have no facts they can point to so as to sustain the assertion.

d. The presence of demand response in the market benefits all customers.

1. Demand response provides economic benefits to all customers.

Demand Response is a service that some customers sell to the grid. The presence of the services provides significant benefits to all customers—including those who cannot or do not curtail.

As the record in the PJM proceeding demonstrated, the LMP reduction associated with load control produces cost savings that far exceed payments made to demand response. The assertion by some parties that payment of LMP is a "subsidy" or "incentive" is misleading rhetoric at best. Those PJM customers who benefitted in August 2006 from a $650 million reduction in LMP were presumably glad to provide the so-called "subsidy" or "incentive" of $5 million. Indeed, there is no good public policy which supports depriving those other customers (and the RTO) of the opportunity to satisfy their demand by means of a more economic resource.

The August 2006 experience provides just one specific example of the benefits of demand response to all customers. That experience will be replicated with proper compensation, because demand response creates a new equilibrium (a new grid balance) at a lower quantity of MWhs, which corresponds to a lower LMP. The equilibrium is struck at marginal cost—LMP—

which indicates that the result is indeed efficient. If dispatch of demand response enables us to satisfy all of our preferences and our collective need for electricity at a cost of $90, versus a cost of $100 absent demand response, the former situation represents an efficiency gain. The new equilibrium at a lower LMP still provides sufficient revenue to all generation that clears the auction. But it also replaces more expensive generation (that does not clear) with less costly demand response bids.

The end result is a lower total spend on electricity by society.

2. Demand response provides unique reliability benefits.

One challenge in preserving reliability on the grid seems constant—the difficulty in siting generation close to concentrations of load. This difficulty leads to congestion, and higher LMPs in the congested areas.

The most common answer to this challenge is to build high-voltage transmission lines to link generation to distant load centers. This answer, however, overlooks the obvious: that the concentration of demand in load centers means that demand-side resources can be plentiful in those same areas where it is difficult to site generation and where it may also be challenging to site transmission.

In other words, demand response is a resource that can be sited much more easily than generation or

transmission in the areas where it is needed most for reliability.

e. Compensation at LMP provides the right signal to tie the customer's decision to curtail load with the needs of the grid and with the needs of customers generally.

Where wholesale markets price electricity at the margin, DR customers have the interest and capability to participate in the market as a seller of a service that achieves the desired outcome. The service that the customers are selling is curtailment of energy on the grid, that is, their ability to reduce the level of generation required to keep the grid in balance. They do this by substituting for what otherwise would be consumption of power from the grid, by either operational changes that temporarily reduce overall consumption, a shift in consumption through storage activities, production of power from an internal source or, increasingly, a combination of all three.

A customer choosing to offer curtailment service to the grid must undertake a fairly complex decision making process. For example, assume a single bus on the PJM system with two generators. The low cost generator will make 80 MW available at $75/Mw. The high cost generator will make 100 MW available at $100 Mw. If load is 100 Mw, the RTO will employ its security constrained economic dispatch protocol and dispatch the first generator's 80 MW and will dispatch the second generator at 20 MW. Both generators will be paid $100.

Now assume that there is an end user with a 50 Mw load and a variety of resources available: some solar generation; a 20 Mw cogeneration plant; some fork-lifts. Also, assume that it is a Wednesday and this customer's cogeneration plant was scheduled for maintenance.

When looking at the scenario set forth above, this customer could decide to defer the maintenance to the weekend and instead offer 20 Mw of curtailment (that is, by choosing to run his co-generation for 20 Mw) into the market at $75/Mw. But this is not a simple, cut and dried decision. The customer will have to weigh a number of issues, such as the fact that there will be a cost to it in terms of overtime labor if maintenance is deferred to the weekend. Also, the customer will have to incorporate into its decision making an estimate of the price it will receive for the curtailment service for the next few days—and will that price cover the overtime maintenance cost.

Obviously, the customer weighing these decision points will be far more likely to choose to curtail load and incur the deferred maintenance cost if it is assured through the day ahead market that it will receive the $75 LMP price than if it receives a lesser payment. The $75 LMP may make the choice worthwhile for the customer whereas a lesser compensation would not.[5]

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[5] Any decision to curtail load will involve either real costs or opportunity costs for the customer. The existence of these costs should be acknowledged in setting the compensation for Demand Response.

And from society's perspective, if the customer chooses to curtail load, LMP is reduced from $100 to $75; all customers benefit; and reliable service is provided at a lesser cost to the grid. A $100 resource has been displaced by a $75 resource.

On the other hand, if the market rules offered this customer less compensation, something that was insufficient to incent the customer to defer the maintenance and run its cogeneration—the result is quite different: dispatch of the high cost generator at $100/Mw; a higher LMP ($100) for all MW of generation and a higher cost for all customers. In short, the poor choice of market rules has cost the grid, society, and all customers.

Compensation for demand response should acknowledge that these costs and complexities exist. Just as customers incur costs in order to engage in demand response, so too do curtailment service providers. CSPs must build their systems (communications systems, network operations centers, etc) from scratch. These costs must also be acknowledged when considering demand response compensation.

f. Compensating demand response and generation comparably will help support the integration of storage and renewable resources into the grid.

The other great evolutionary trend which is occurring in the electric industry is the increased emphasis on deployment of distributed resources, particularly intermittent renewables and storage resources. The increased deployment of intermittent renewable re-

sources creates an operational challenge which grid operators must deal with. Demand Response is a valuable tool in the grid operator's portfolio for addressing the problem of intermittency. In the past, the intermittency has been addressed by adding back up generation, typically gas fired units. But price responsive, active load management can also be relied upon to provide the firming service for intermittent renewables. From an operational perspective, the grid operator can dispatch controllable load to address a drop in wind generation, rather than calling on a gas fired unit. And from an environmental perspective, provision of this firming service by demand response is clearly preferable to operation of a gas unit. And from an economic and efficiency perspective, society is better off if the demand response is dispatched, so long as it clears in a competitive auction.

As noted, we can also expect increased deployment of storage devices as the industry evolves. Demand response is a valuable tool for maximizing the value of storage. Indeed, the synergies that exist between renewable generation, storage, and demand response constitute a virtuous circle. The value of storage can be maximized by having the storage filled or charged during usage valleys when load—and prices—are low. The value to the grid and society is that a sink has been created for a renewable source, such as wind generation, which might otherwise be spilled. The value chain continues when the storage can be discharged the next day when load—and prices—are high. The value to the grid and society is that a peak

has been cut. And the discharge of the storage device will appear to the grid as demand response.

The net effect of the intersection of renewables, storage and demand response is the filling in of a usage valley and the curtailment of a usage peak. To the extent that demand response reduces peak load, it increases the load factor of the grid—an important measure of efficiency. Simply stated, avoiding the need to build generating plant that runs very few hours per year is an efficient thing to do. The Brattle Report prepared for the Staff last year made this point, noting that maximum encouragement of demand response could help the nation avoid the construction of many peaking plants.

From the perspective of the individual customer, he has curtailed his usage of high cost power, and has substituted low cost power and storage instead. The level of compensation provided to the end-user for his demand response is crucial to the effectiveness of this evolution. Given the benefits to the grid noted above, and the fact that the load management provided in this scenario has the same wholesale value as an increment of supply, the appropriate price to pay for the curtailment service is LMP. LMP reflects the value of the service provided to the grid, it reimburses the costs the customer incurs to engage in demand response, and it provides compensation which can be used to further our policy goals of increased reliance on distributed resources, including renewables, demand response, and storage devices.

***Issue*: Whether payment of LMP should apply to all hours and, if not, the criteria to be used for establishing the hours when LMP should apply.**

a. LMP should apply in all hours.

LMP payments should apply to all hours. LMP reflects the cost which society avoids by virtue of demand response service being provided. Therefore, the LMP in a given hour reflects the economic value of the service in that hour. The fact that demand response reduces the total resources society must expend to satisfy load should be the pre-eminent factor in the Commission's deliberation of this issue.

b. The theory that demand response will impose net costs on non-participating customers in some hours is largely hypothetical.

Several commentators will assert that demand response will impose net costs on non-participating customers. This concern is hypothetical at best, and reflects a scenario which is not likely to occur in the real world.

In that scenario, demand response represents a large proportion of the resources offered (meaning a relatively large cost) and the LMP is very low (meaning a flat part of the curve such that demand response does not reduce LMP). This scenario is not likely to occur because there will not be large amounts of demand response offered at very low LMPs. Like any other service, the quantity offered will increase as the price increases. Given the costs (financial, operational, comfort, etc.) associated with demand response, it is

not likely that a great deal of demand response will occur at very low LMPs.

c. The Commission should review the costs and benefits of demand response with LMP compensation—periodically, but not hourly.

The public interest does not turn on an hour by hour analysis of costs and benefits. A more rational approach would be to review the annual effect of paying LMP compensation in all hours. Therefore, we suggest that the Commission adopt the proposed rule and review its overall costs and overall benefits at some reasonable milestone. If the review shows that customers are receiving net positive benefits when compensation is set at LMP, the Commission can leave the rule unchanged; if not, the Commission can certainly consider and implement changes.

d. If the Commission's concern focuses on the possibility that demand response could impose net costs on customers in one or more particular hours, solutions are available.

If the Commission does not agree that the overall costs and benefits of LMP compensation to demand response should be evaluated at a reasonable milestone, and that the greater concern is the possibility of net costs in individual hours, the following considerations are appropriate.

First, the Commission could adopt a dynamic threshold for full LMP compensation in which the LMP compensation is paid only if the effect of including load curtailment in the dispatch and paying for it is positive

in any given hour. In effect the ISO would calculate the auction results twice—once with load curtailment dispatched and compensated, and once with the load curtailment not dispatched and not compensated. Curtailments would be paid the clearing price only if the cost to ratepayers is less with load curtailments included in the dispatch. In effect, load management would be compensated only if the LMP- reducing effect of curtailment is larger than the cost of the demand response.

The Commission could also adopt a static threshold which would represent a reasonable proxy for a calculation of the cross over point at which load management costs begin to exceed the benefits. The static threshold, if developed properly, will reflect the fact that demand response is cost effective over a wide range of loads, and reduces LMP at any price where there is a slope to the supply curve. So long as the curve is sloped, and not flat, load management is displacing a more costly generation alternative- and is providing benefits. Academic research in the PJM markets indicates, for example, that the socially optimal trigger point is in the range of $66-$77/Mwh. See Walawalkar, Blumsack, Apt, and Fernands (Energy Policy, An economic welfare analysis of demand response in the PJM electricity market, August, 2008).

Issue: **How should demand response payments be allocated and who should pay for full LMP compensation.**

The Commission should require immediate implementation of the proposed compensation rule along

with guidance that the RTOs shall continue to allocate demand response payments in the manner that they currently do. This approach is easily implemented and will prevent the issue of allocation from being used as a device to stall implementation of the compensation rule. The Commission could also make it clear that the RTOs are free to explore different allocation mechanisms through their stakeholder processes but that the Commission will not delay implementation of the proposed rule.

There is an alternative allocation method that the Commission could consider which has the added benefit of also resolving the so-called missing money problem raised by the LSEs. The Commission could adopt a rule with the following features: 1) the ISOs charge load a price which is derived by dividing the revenue requirement by (load minus the demand response). 2) This will produce revenue in excess of the clearing prices paid to generation and demand response together. 3) The excess revenue is returned as appropriate to load (LSEs). It is worth noting that the Commission has approved similar mechanisms before. For example, in PJM FTRs are funded in a similar fashion in that all load in a zone is charged the LMP but only generation located within the zone is paid the LMP This produces excess revenue which is used to fund FTRs.

CONCLUSION

Viridity Energy respectfully requests that the Commission consider these Comments and, in a Final Rule, adopt regulations requiring the payment of full

locational marginal pricing to eligible demand response resources, without delay, in organized wholesale energy markets.

Respectfully submitted,

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UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. RM10-17-000

Demand Response Compensation in Organized
Wholesale Energy Markets

[May 13, 2010]

COMMENTS OF THE AMERICAN PUBLIC POWER ASSOCIATION AND THE NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION

The American Public Power Association (APPA) and the National Rural Electric Cooperative Association (NRECA) submit these comments on the Commission's Notice of Proposed Rulemaking (NOPR) issued in this proceeding on March 18, 2010.[1] The NOPR proposes a specific approach for compensating demand response providers, which the Commission believes would improve the competiveness of centralized wholesale energy markets administered by Regional Transmission Organizations (RTOs) and ensure just and reasonable rates. The memberships of

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[1] Demand Response Compensation in Organized Wholesale Energy Markets, 75 Fed. Reg. 15,362 (proposed Mar. 29, 2010) (Notice of Proposed Rulemaking). In the Notice, the Commission also announced that it was terminating the proceeding *PJM Interconnection, LLC* in Docket No. EL09-68-000. *Id.* at 15,367.

APPA and NRECA are national leaders in participation in demand response activities. APPA and NRECA appreciate the opportunity to comment on the NOPR.

The NOPR proposes to amend Chapter I, Title 18, Section 35.28 of the *Code of Federal Regulations* by adding a new paragraph (g)(1)(v):

> **§ 35.28 Non-discriminatory open access transmission tariff.**
>
> (v) Demand response compensation in energy markets. Each Commission-approved independent system operator or regional transmission organization that has a tariff provision permitting demand response resources to participate as a resource in the energy market by reducing consumption of electric energy from their expected levels in response to price signals must pay to those demand response providers, in all hours, the market price for energy for these reductions.

While APPA and NRECA welcome an inquiry into the compensation of demand response bidders in RTO-run markets, they cannot support the proposed regulation as stated. While many of the RTO-run centralized markets have programs that use locational marginal prices (LMP) as a guide to incent economic demand response, the exact formulation varies among the RTO-run markets. APPA and NRECA believe it is wiser to allow RTOs and the stakeholders in their regions to implement their own variations on demand response incentives in response to local and regional

needs, rather than prescribe only one method of compensation.

The Commission requests comments on nine items, and APPA and NRECA respond to each request herein. Those comments should be consulted for a complete understanding of the positions of APPA and NRECA. APPA and NRECA also provide an executive summary for the convenience of readers.

I.

EXECUTIVE SUMMARY

The members of APPA and NRECA are recognized as national leaders in demand response.[2] Many of the members have programs for direct control of HVAC systems, have interruptible contracts with certain retail customers, utilize dynamic pricing and advanced metering, or engage in other demand response activities. While the members of each organization have differences, they are all consumer-owned load serving entities ("LSEs") and take very seriously their obligation to provide consumers with reliable power at the lowest reasonable cost over the long term. Where demand response makes economic sense in meeting that obligation, APPA and NRECA members have proven that they are strong supporters of demand response.

APPA and NRECA are each participating in the proceeding concerning the National Action Plan on Demand Response in Docket No. AD09-10-000, in which the Commission is formulating an action plan for

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[2] *See infra* Section II, Interests of APPA and NRECA.

implementation of demand response throughout the states, regions and localities. In the NOPR, the Commission appears to divert from the broad and inclusive approach of the proposed National Action Plan, by prescribing one method of compensation for demand response that bids into RTO-run wholesale energy markets. APPA and NRECA, however, support allowing local and regional differences to be reflected in pricing rules in RTO-run markets. APPA and NRECA also believe the NOPR fails to recognize the very substantial demand response activity in areas of the country that do not have RTO-run markets. APPA and NRECA members have been successfully pursuing demand response even before the advent of RTO-run markets.

The NOPR applies only to demand response acting as a wholesale resource in RTO-run markets and does not address more traditional retail-level demand response programs. The Commission distinguishes price-responsive demand response and focuses on only demand response resources in RTO-run markets. Regarding compensation for wholesale demand response acting as a resource in RTO-run markets, APPA and NRECA agree with the suggestion of Commissioner Moeller that a Notice of Inquiry would be preferable to a prescriptive NOPR. The NOPR does not address the variations on incenting demand response resources in the various RTO-run markets and lacks sufficient justification for proposing a uniform compensation approach. The NOPR incorrectly attributes the benefits of demand response considered

broadly, to support the bidding of demand response as a wholesale resource.

APPA and NRECA support the Commission's goal in Order No. 719 of eliminating barriers to demand response in RTO-run markets. However, the NOPR fails to explain how the lack of a uniform compensation approach in each RTO-run market is a barrier to demand response. APPA and NRECA members located in RTO-run markets have supported tailored incentives to encourage economic demand response resources. While participation in economic demand response programs in several RTO-run markets has declined in 2009, compared to 2008, this reflects the decline in RTO prices during that timeframe, and it is not, in itself, a reason to prescribe a uniform compensation approach based on paying full LMP to demand response resources.

For these reasons, APPA and NRECA respectfully request that the Commission refrain from implementing its proposed regulation set out in the NOPR, and instead issue a Notice of Inquiry if it believes that further proceedings in this docket are required.

II.

INTERESTS OF APPA AND NRECA

APPA, NRECA, and their respective members may be directly affected by the outcome of this proceeding. APPA is the national service organization representing the interests of not-for-profit, publicly owned electric utilities throughout the United States. More than 2,000 public power systems provide over 15 percent of

all kilowatt-hour sales to ultimate customers, and do business in every state except Hawaii. Public power systems own almost 10 percent of the nation's electric generating capacity, but they purchase nearly 70 percent of the power used to serve their ultimate consumers. Public power systems own about eight percent of the nation's higher voltage lines (138 kV or greater), but many must use the transmission facilities of public utilities to move their power supplies to their loads.

APPA members offer a variety of demand response services to their customers. A 2008 APPA survey of public power utilities found that 54 percent of respondents had time-of-use or incentive rate programs and that 43 percent of respondents offered load response (peak shaving) programs.[3]

Examples of public power systems' demand response programs include the following:

- JEA, serving Jacksonville, Florida, offers curtailable service rates, interruptible service rates, and time-of-use rates;
- The Medford, Wisconsin public power utility offers time-of-day service rates to its residential, commercial, and industrial customers;

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[3] AMERICAN PUBLIC POWER ASSOCIATION, RESULT OF THE 2008 ENERGY SERVICES SURVEY FOCUSING ON ENERGY EFFICIENCY, DEMAND-SIDE MANGAGEMENT, AND CONSERVATION PROGRAMS AT PUBLIC POWER UTILITIES, (2008).

- Crawfordsville Electric Light & Power in Indiana offers a peak management program for cycling air conditioners and water heaters;
- Colorado Springs Utilities in Colorado offers a peak demand rebate program for large business customers that can provide a minimum of 10 kilowatt demand reduction during the summer peak period; and
- A 2009 report issued by the California municipal utilities found that 17 public power utilities in California offer demand response programs, including thermal energy storage incentive, interruptible rates, peak shaving, interruptible rates, and smart meter installation.

APPA and the public power systems that it represents therefore have a vital interest in demand response compensation issues.

NRECA is the not-for-profit national service organization representing 930 not-for-profit, member-owned rural electric cooperatives. The great majority of these cooperatives are distribution cooperatives that provide retail electric service to over 42 million consumer-owners in 47 states. Kilowatt-hour sales by rural electric cooperatives account for approximately 10 percent of total electricity sales in the United States. In addition, NRECA members include 66 generation and transmission cooperatives that supply wholesale power to their distribution cooperative owner-members. Both distribution and G&T cooperatives were formed to provide electric service to their

owner-members at the lowest reasonable cost consistent with adequate and reliable service.

Although cooperatives provide only about 10% of the country's total retail energy sales, their combined demand response resources equal almost 20% of demand response capacity of the electric sector. Research conducted by NRECA found that approximately half of cooperatives have installed at least some advanced metering infrastructure on their systems, and some 30 percent of cooperatives have begun to integrate their advanced metering infrastructures with other systems on their grid, such as their outage management systems and their geographic information systems.

In a 2004 survey of its members, NRECA found that more than 40 percent of respondents had some kind of demand response program in place. Of those:

- 77% had programs in place for direct control of water heaters, pool heaters, air conditioners, and storage and dual-fuel heating systems;
- 44% had interruptible contracts with some of their consumers;
- 30% had time-of-use or other forms of dynamic pricing;
- 16% had arrangements for voluntary "share-the-savings" interruptions;
- 11% had other demand response programs in place. Most of these involve control of irrigation loads—a significant load in some coopera-

tive service areas—or the ability to dispatch customer-owned generation.

Cooperatives' success with demand response is the product of many years of concentrated effort to make demand response a critical cost-cutting and risk management tool in the conduct of electric cooperatives' basic business: supplying their consumer-members' electricity needs.

III.

COMMUNICATIONS

APPA and NRECA request that service in this proceeding be made upon, and communications be directed to, the following persons:

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IV.

COMMENTS

APPA and NRECA welcome an inquiry into the compensation of demand response bidders in RTO-run markets. While many of the RTO-run markets have programs that use LMP as an input to incent demand response participation, the exact formulation varies among the RTO-run markets. APPA and NRECA believe it is wiser to allow RTOs and their stakeholders in specific centralized markets to implement their own variations on demand response incentives that are tailored to local and regional needs, rather than prescribe one method of compensation.

In Paragraph 20 of the NOPR, the Commission requested comments on nine items, and APPA and NRECA respond to each request in turn.

1. **"We [. .] seek comment on the need to compensate demand response acting as a resource in organized wholesale energy markets. Commenters may address whether current compensation for demand response providers acting as a resource in the organized wholesale energy markets is adequately procuring demand response."**

The members of APPA and NRECA are recognized as national leaders in demand response and engage in a wide variety of demand response activities. As consumer-owned LSEs, they take very seriously their obligation to provide consumers with reliable power at the lowest reasonable cost over the long term. Where demand response makes economic sense in meeting that obligation, APPA and NRECA members have proven that they are strong supporters of demand response in the RTO-run markets and in the bilateral markets.

Demand response comes in many forms, and compensation comes in several ways. Demand response, including load management, dynamic pricing and interruptible load, can lower prices in *both* RTO-run markets and bilateral markets by reducing the need to dispatch higher-priced generation, and by reducing the need to build new generation. The NOPR incorrectly claims benefits from the broad use of demand response as justification for paying full LMP to demand response providers.[4] The benefits of demand response

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[4] For example, the NOPR cites to a New York Independent System Operator, Inc. (NYISO) study reporting on the benefits of demand response. 75 Fed. Reg. at 15,364 n.11. That Study, however, referred to the benefits of Special Case Resources, which are

often have nothing to do with the hourly energy price in an RTO-run market.

Turning specifically to participation in the hourly RTO-run markets, APPA and NRECA agree that there is a need to compensate demand response resources that participate in the RTO-run markets. Members of APPA and NRECA that are located in RTO-run markets have supported reasonable incentives to encourage demand response resources to participate in economic programs. However, all sources of compensation need to be considered, including foregone costs of customers paying retail rates. As the Commission observes, the appropriate level of compensation is the subject of debate.[5]

Commissioner Moeller in his partial concurrence/dissent correctly formulates the issue: "The debate centers on whether demand response resources should be *paid* the LMP or should realize the *value* of LMP if they chose to reduce demand."[6] There is considerable support for the position that there should be an offset to payment of full LMP:

- "In the absence of dynamic retail pricing, another option for providing real-time economic demand response resources the same incentives would be to pay equal to the difference between

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capacity demand response providers, and not the Day Ahead Demand Response Program, which is for economic demand response resources.

[5] 75 Fed. Reg. at 15,366-67.

[6] 75 Fed. Reg. at 15,370 n.9 (emphasis in original).

the wholesale LBMP and the retail customer's rate to address the economic barrier."[7]

- "The purpose of PJMs demand side Economic Program is, or should be, to address a specific market failure, which is that many end use customers do not pay the market price, or LMP. The current compensation structure is consistent with the purpose of the demand side program, in that the hourly LMP replaces only the generation component of retail rates in order to provide the appropriate wholesale market price signal to customers, so for any reduction in the program, customers receive LMP less the generation component of the applicable retail rate and, any compensation in excess of that is a subsidy."[8]
- "For example, the Midwest ISO may be able to expand its EDR initiative to make it a price responsive demand program for economic demand response resources. An efficient payment in such a program is equal to the difference between the wholesale LMP and the retail customer's rate. Paying this amount aligns the loads' incentives with the value of the energy to the system, which would directly address the regulatory barrier described in the prior section [i.e.,

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[7] NYISO Independent Market Monitor Report on Demand Response, in Docket No. RM07-19, AD07-7, at 14-15 (May 15, 2009).

[8] PJM Interconnection, LLC (PJM) Independent Market Monitor Report on Barriers to Demand Side Response, Docket No. ER09-1063 at 2-3 (July 1, 2009).

> lack of dynamic retail pricing/fixed retail rate regimes at state level]."[9]

Economic demand response compensation is an incentive designed to increase its market participation, not a payment to a resource that is fully comparable to a supply resource (as discussed below). This is evident from the definition of "demand response" in the Commission's Regulations:

> Demand response means a reduction in the consumption of electric energy by customers from their expected consumption in response to an increase in the price of electric energy or to incentive payments designed to induce lower consumption of electric energy.[10]

Since the Commission removed price-sensitive demand response from the NOPR, that leaves only incentive payments designed to lower consumption as the subject of the NOPR. Since an incentive payment may involve out-of-market costs, it is likely that other market participants will be paying these costs. Therefore, care must be taken in setting compensation for demand response resources participating in RTO-run markets.

In considering whether current compensation for demand response resources is adequate to incent sufficient demand response, the Commission should con-

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[9] Midwest Independent Transmission System Operator, Inc. (MISO) Market Monitor Report at 15-16 (Apr. 28, 2009).

[10] 18 C.F.R § 35.28(b)(4)(2010).

sider recent price activity. While participation in economic demand response programs in several RTO-run markets has declined in 2009, compared to 2008, this reflects the decline in RTO energy prices during that timeframe. In the Northeast, wholesale energy prices declined by roughly 50 percent in 2009 compared to 2008. A decline in prices would, logically, mean that participation in economic demand response programs may decline.

For example, the NYISO reports that 2009 offer activity increased by 28 percent in its economic program, the Day Ahead Demand Response Program (DADRP). However, 79 percent fewer hours were scheduled.[11] It should come as no surprise that, as prices decline, demand response resources are selected less often, even when the number of bids increases.

APPA and NRECA support the Commission's goal in Order No. 719 of eliminating barriers to demand response in RTO-run markets. However, the NOPR fails to explain how the lack of a uniform compensation approach in each RTO-run market is a barrier to participation by demand response resources.

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[11] NYISO Demand Response Programs Report, Docket No. ER01-3001-024 (Jan. 15, 2010).

2. **"We further solicit comment on alternative approaches to compensating demand response resources participating in organized wholesale energy markets, and the merit of those approaches in comparison to the one proposed here."**

APPA and NRECA support allowing local and regional differences to be reflected in pricing rules in RTO-run markets. In general, demand response rules in RTO-run markets have evolved to meet specific needs. Local and regional conditions largely determine what form and what compensation level for demand response is appropriate. The availability of particular resources in a particular region can mean that different compensation levels are needed to optimize the development of demand response. Varying consumer load profiles and retail market structures dictate that different compensation levels are appropriate in different RTO-run markets.

The Commission notes that there are variations in how the RTO-run markets utilize the payment of LMP as an incentive.[12] APPA and NRECA support the system-by-system approach currently allowed by the Commission. At this time, APPA and NRECA do not advocate for one compensation approach over another.

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[12] 75 Fed. Reg. at 15,364-65.

3. **"In particular, we ask for comment on whether a reduction in consumption is comparable to an increase in electricity production for purposes of balancing supply and demand, and whether, therefore, demand response providers and generators should receive comparable compensation."**

Many stakeholders believe that it is appropriate to pay demand response resources "comparable" compensation as an incentive—the issue is what is "comparable."

For a balancing authority to meet load requirements and maintain a reliable electric system, a one megawatt reduction in demand is generally comparable to a one megawatt increase in generation. However, that does not mean that a demand response resource is "equivalent" to a supply resource. The generator gets paid LMP for a one megawatt increase in supply, while the retail customer does not have to pay for the one megawatt reduction. While demand response is valuable because of its positive environmental attributes and its salutatory effect on peak usage to avoid investments in new generation, it is not a "resource" like generation, in that it cannot actually power residences, commercial establishments or industrial facilities.

It is not unjust and unreasonable to treat demand response resources differently than generators and other suppliers. By analogy to Order No. 890, demand response, generation and transmission are to be treated "comparably," but it does not follow that each

of them is "the same" and therefore must be compensated in the same manner.

4. **"We further seek comment on whether paying LMP to demand response resources is comparable compensation or is more or less than comparable to compensation paid to generation in the ISO and RTO energy markets."**

APPA and NRECA comment that paying the full LMP to demand response resources is an incentive and is effectively the payment of more compensation than the compensation paid to suppliers in RTO-run markets. The question of how much to incent demand response resources in wholesale markets arises because (for a wide variety of very good technical, economic, and political reasons) retail customers do not commonly pay the real-time wholesale price for power, even in regions with RTO-run markets. As CAISO's Market Surveillance Committee ("MSC") asserted:

> [T]he failure to set the default wholesale price paid by all California consumers equal to hourly real-time price, instead setting a fixed default retail price that does not vary with real-time system conditions, significantly dulls the incentive for final consumers to participate actively in California ISO markets.[13]

Similarly, The PJM Monitor stated:

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[13] California Independent System Operator Corp. (CAISO) Market Surveillance Committee Comments on Barriers to Demand Response and the Symmetric Treatment of Supply and Demand Resources, Docket No. ER09-1048 at 1 (filed July 1, 2009).

> Customers who pay the hourly LMP in their retail rate are already exposed to the real time market price of electricity any additional payment made to these customers in addition to the direct saving results in a subsidy that is not aligned with the objective of the program. Customers who pay the real time LMP should not be eligible for payments under the PJM Economic Load Response Program. This subsidy is not necessary as the market failure in question does not exist for these customers.[14]

Were retail customers to see that real-time price and have the technical ability to respond to it, no further compensation for demand response would be necessary. Given the many good reasons not to move to that regime, however, APPA and NRECA recognize the value of providing demand response resources carefully crafted incentives in appropriate circumstances, which should be determined, at least in the first instance, by each RTO and its stakeholders.

5. **"We also request comment on whether payment of LMP should apply to all hours, and, if not, the criteria that should be used for establishing the hours when LMP should apply."**

APPA and NRECA note that there are differing rate practices among RTO-run markets on this issue. APPA and NRECA support recognizing regional dif-

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[14] PJM Independent Market Monitor Report on Barriers to Demand Side Response, Docket No. ER09-1063 at 21-22 (filed July 1, 2009).

ferences. Some RTO-run markets, including NYISO and ISO New England, Inc., use an offer floor price to minimize free ridership and promote efficient cost allocation. Each RTO and its stakeholders are in the best position to determine the criteria for establishing the hours in which demand response resources should be compensated.

In addition, there is no evidence offered that demand response resources improve the competitiveness of RTO-run markets in non-peak hours. For example, the Commission cites the study conducted by PJM that simulated the effect of demand response on prices and indicated that a three percent load reduction in 100 peak hours produced a price decline of six to 12 percent. 75 Fed. Reg. at 15,364. This price effect has been observed in other RTO-run markets. However, there is no evidence presented to show what the price effect is in non-peak hours.

6. **"Additionally, we seek comment on whether requiring payment of LMP is appropriate across all ISOs and RTOs, or whether variations among ISOs and RTOs justify varying levels of demand response resource compensation."**

As noted above, APPA and NRECA support the recognition of regional differences. Each RTO-run market is in the best position to determine the levels of incentives and compensation for demand response resources based on a myriad of factors. Among these factors are the degree of dynamic pricing, the extent of retail access in a region, the amount of behind-the-

meter generation, and the level of variable resource penetration, among other factors.

7. **"To that end, we further seek comment on whether the Commission should allow regional variations for an ISO or RTO that does not seek to compensate demand response resources participating in the organized wholesale energy market."**

At this point, there does not appear to be a need to comment, since there does not appear to be an existing RTO-run market that does *not* intend to compensate demand response resources that operate in its markets.

APPA and NRECA note that the Southwest Power Pool (SPP) maintains that demand response resources are treated comparably to other resources in its Energy Imbalance Service Market. SPP states that it has facilitated registration by demand response resources offering behind-the-meter generation and load response, and such resources have participated in the Energy Imbalance Service Market. The Commission has stated that it "understands that SPP's demand response program is in its nascent stages in the Energy Imbalance Service Market, and at this time SPP may not have sufficient information regarding any known barriers to comparable treatment of demand response resources."[15]

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[15] *Southwest Power Pool*, 129 FERC ¶ 61,163 at P 96 (2009).

8. **"Accordingly, we also seek comment on whether, and under what circumstances, the Commission should conduct periodic reviews of demand response compensation and the criteria that should be used in making such assessments."**

APPA and NRECA have no comment at this time.

9. **"With specific regard to the proposed regulatory text set forth below, we seek comments on whether terms such as 'expected levels', 'price signals', and 'market prices' are sufficiently defined."**

APPA and NRECA have no comment because they do not support the proposed regulation as stated.

WHEREFORE, APPA and NRECA respectfully request that the Commission refrain from implementing its proposed regulation set out in its NOPR, and instead issue a Notice of Inquiry if it believes that further proceedings in this docket are required.

Date: May 13, 2010

Respectfully submitted,

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UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Docket Nos. RM10-17-000, EL09-68-000

DEMAND RESPONSE COMPENSATION IN ORGANIZED WHOLESALE ENERGY MARKETS

[May 13, 2010]

COMMENTS OF THE NEW YORK INDEPENDENT SYSTEM OPERATOR, INC.

The New York Independent System Operator, Inc. ("NYISO") respectfully submits this response to the Commission's March 18, 2010 *Notice of Proposed Rulemaking* ("NOPR") seeking comments on a series of questions and its proposed new regulation concerning demand response compensation in energy markets.[1] As a member of the ISO/RTO Council ("IRC") and a signatory to the joint IRC filing made in this proceeding, the NYISO also fully supports the responses to the NOPR and additional discussion presented in the IRC White Paper entitled *Demand Response Pricing in Organized Wholesale Markets*

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[1] Demand Response Compensation in Organized Wholesale Energy Markets, Federal Energy Regulatory Commission Notice of Proposed Rulemaking, 130 FERC ¶ 61,213, Issued March 18, 2010 (Docket Nos. RM10-17-000, EL09-68-000 ("NOPR").

("IRC White Paper").[2] The IRC White Paper illustrates the shortcomings of the NOPR proposal to pay LMP for demand response and presents a series of proposals that would avoid those shortcomings while supporting the Commission's goals of just and reasonable rates and encouraging further demand response participation.

Demand response is a valuable resource in the NYISO market for all the reasons the Commission has pointed out—it serves to lower prices by reducing the need to dispatch higher-priced generation, or buy higher priced capacity, it can mitigate generator market power by increasing the risk to generation suppliers that their facilities will not be dispatched if bid at a non-competitive price and it can also support system reliability and address resource adequacy.

Many agree that the most efficient method for encouraging cost-efficient demand reduction by end-users in a market environment is the imposition of dynamic retail pricing (referred to by Professor Hogan as Real-time Pricing Demand Response[3]) whereby retail rates are linked to real-time wholesale market energy prices.[4]

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[2] Comments of ISO/RTO Council, White Paper entitled Demand Response Pricing in Organized Wholesale Markets by William W. Hogan, Docket Nos. RM10-17-000, EL09-68-000 (filed May 13, 2010) ("IRC White Paper").

[3] IRC White Paper, *supra* note 2, at p 2.

[4] *See Id.* at p 6; *See also New York Independent System Operator, Inc.*, Compliance with Order 719, Docket No. ER09- 1142-000, at pp 12-13 (filed May 15, 2009); Report *on Shortage Pricing of Potomac Economics, LTD. Independent Market Advisor for the*

Under such pricing designs, loads are exposed to the wholesale cost of power and have sufficient information to make economically rational consumption decisions. That is, retail loads can avoid consuming when the cost of such consumption exceeds the cost of not consuming and the Commission's goals of lower wholesale prices, market power mitigation and system reliability are realized.

In jurisdictions without Real-time Pricing Demand Response, ISOs/RTOs have some ability to encourage economically similar rational demand reduction by paying demand response providers for reducing their load on the system. If the retail jurisdiction has allowed Load Serving Entities ("LSEs") to charge those demand response providers as if they had not reduced their consumption, a payment of LMP for demand response may be appropriate.

In the absence of such a retail payment construct, however, LMP is not the right price for demand response providers. A more appropriate payment for such reduction is what Professor William W. Hogan has referred to as LMP-G or a payment of LMP minus an imputed amount reflecting some (or all) components of the retail rate.[5] Thus, LMP-G is intended to mimic paying LMP to a demand response provider in a jurisdiction that allowed

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New York ISO, Docket No. ER09- 1142-000, at pp 4-5 (filed May 15, 2009); Potomac Economics, *2009 State of the Market Report New York ISO Electricity Markets*, April 2010, at slide 186, *available at* http://www.nyiso.com/public/webdocs/documents/market_advisor_reports/2009/2009_NYISO_SOM_Fina l_4-30-2010.pdf.

[5] IRC White Paper, *supra* note 2, at p 7-8.

Load Serving Entities ("LSEs") to charge those demand response providers as if they had not reduced their consumption. As such, LMP-G reflects a virtual retail purchase of the commodity being sold at wholesale.

Paying demand response LMP-G will facilitate the entry of economic demand response resources into real-time Energy markets while maintaining the integrity of Locational Marginal Price ("LMP") based, two-settlement Energy Markets. It will provide an efficient incentive for demand resources to participate in wholesale markets while providing a settlement for wholesale customers that is comparable to being supplied by a generation resource. The NYISO suggests that the ISO/RTO develop the details of LMP-G in individual proceedings, working with their stakeholders, rather than develop such a price generally.

The approach to the payment for demand response providers that is set forth in the NOPR, requiring ISOs/RTOs to pay LMP without reflecting the virtual retail purchase of the commodity being sold at wholesale, will impose unnecessary costs on nonparticipating retail customers, create perverse incentives and slow the introduction of other innovative clean technologies by uneconomically suppressing real-time prices without any guarantee that the overpayment inherent in such a rate will foster further investment rather than act as a mere windfall.

To the extent that the Commission concludes that a single payment rule for demand reduction in the organized energy markets is necessary, it should adopt Pro-

fessor Hogan's proposed LMP-G methodology. If the Commission cannot support LMP-G as the appropriate demand response compensation scheme, the Commission should allow individual ISO/RTOs to develop the appropriate rate to pay for demand response in the energy markets of their individual jurisdictions, in proceedings that involve all stakeholders.

I. COMMUNICATIONS AND CORRESPONDENCE

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II. BACKGROUND AND SUMMARY RESPONSE

The Commission has long been directing ISOs and RTOs to open their electricity markets to demand response providers by reducing barriers and revising market rules that may have unnecessarily prevented their entry. The NYISO has responded by providing oppor-

tunities for wholesale demand response resources to participate in its markets.

Wholesale demand response resources may participate in the NYISO's Day-Ahead Energy market through the Day-Ahead Demand Response Program ("DADRP"), and in the Day-Ahead and real-time Ancillary Services markets through the Demand-Side Ancillary Services Program ("DSASP"). They may also participate as suppliers of Installed Capacity ("ICAP") when they agree to participate as Special Case Resources ("SCR") in the emergency reliability services program described below.

In the DSASP and ICAP programs, demand response providers and generators are paid on an equal footing—both are eligible for clearing prices associated with the services they are chosen to provide.[6] In the DADRP program, wholesale demand response providers are also paid for their scheduled demand reduction in the same way that Generators are paid for Day-Ahead scheduled Energy.[7]

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[6] ICAP is awarded for a month at a time; Ancillary Services are scheduled daily. ICAP can be awarded through an NYISO auction or bilaterally with a Load Serving Entity.

[7] Demand response providers and generators in the ICAP and DSASP programs are paid the clearing price for the availability of energy when required by the ISO and compensation comparability in these programs is appropriate. An identical $ / MW paid for either demand response or generation availability in these programs imposes the identical impact on loads.

Day-Ahead-scheduled DADRP compensation is also comparable to Day-Ahead scheduled generation compensation. The NYISO developed DADRP nine years ago when demand response was in

As well, demand response is the only resource eligible to offer emergency reliability services when the NYISO forecasts an operating reserve shortage.[8] With a best efforts 21-hour-ahead advisory, and a two-hour ahead notice, these resources receive the greater of $500/MWh or the real-time LBMP, or the real-time LBMP,[9] for every MWh of demand reduction provided, with a guaranteed minimum number of hours over which they are eligible for this compensation.

Most recently, as the Commission notes, Order No. 719 implemented a series of reforms to improve the competitiveness of organized electric markets. In particular, the NYISO was directed in its Order No. 719 compliance proceeding to:

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its infancy and may review this design depending on the outcome of this proceeding. As noted in the NYISO's Sept. 7, 2004 DADRP filing, "In the event that [the NYISO] determines that Market Participants have sufficient incentives to pursue economic demand reductions as a result of being subject to real-time prices or other initiatives, the NYISO will reconsider the continued need for an incentivized DADRP." (*New York Independent System Operator, Inc.*, Docket No. ER04- 1188-000, Filing of Services Tariff Revisions to Extend and Modify Its Incentivized Day-Ahead Economic Load Curtailment Program (filed Sept. 7, 2004).

[8] *See* Services Tariff, Section 5.12.11 (a) and Services Tariff Attachment G.

[9] Payments vary by program and by the number of hours included in the specific request to respond. *See* Services Tariff Section 5.12.11 (a) and Services Tariff Attachment G.

> [M]odify its tariff to allow technically capable demand response resources to participate in the real-time energy market.[10]

The NYISO has begun this effort with stakeholder discussions of the concept for real-time market participation by demand response to continue for the balance of 2010.[11] The NYISO expects that these stakeholder proceedings will provide market designs that not only include appropriate compensation but also address other design issues such as the need for minimum run times that may differ from those default times currently included for generation resources, aggregation opportunities not necessary for generation resources, bid protections, and new scheduling options (*i.e.* 5 or 15 minute flexible schedules).

In this NOPR, the Commission has turned its attention to compensation for demand reduction in the energy markets. The NYISO provides brief answers to the questions asked by the Commission below. Further descriptions of the NYISO position on the issues raised by the Commission's questions can be found in the balance of this response.

> [Whether] current compensation for demand response providers acting as a resource in the organized wholesale energy markets is adequately procuring demand response

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[10] *New York Independent System Operator, Inc.*, 129 FERC ¶ 61,164, at P 34 (2009).

[11] *New York Independent System Operator, Inc.*, Docket No. ER09-1142-006, Order No. 719 Demand Response Compliance Filing, Letter Order (filed April 23, 2010).

Because the NYISO has no criteria by which to measure the Commission's conception of "adequate" procurement, it is difficult to answer this question. As Professor Hogan indicates, however, it is likely that in the absence of dynamic retail pricing, direct compensation from the ISO/RTO may be a useful market signal to encourage more economically efficient demand response. It is vitally important, however, as the Professor also asserts, that such direct compensation not impose a net loss on the ISO/RTO or create perverse incentives that would hinder economically appropriate behavior in other areas of the market.

> [W]hether a reduction in consumption is comparable to an increase in electricity production for purposes of balancing supply and demand, and whether, therefore, demand response providers and generators should receive comparable compensation; [and]
>
> [W]hether paying LMP to demand response resources is comparable compensation or is more or less than comparable to compensation paid to generation in the ISO and RTO energy markets

An increment of consumption, in an LMP-based, two-settlement energy market, has the same value as an increment of generation. This does not translate, however, to a conclusion that compensating an increment of demand reduction the same as an increment of electricity production is appropriate for purposes of balancing supply and demand. LMP is not comparable compensation

for both demand reduction and generation supply.[12] To the extent LMP rather than LMP-G is paid, the ISO/RTO would be over-compensating demand reduction at the expense of non-participating customers and other competing technologies not eligible for the subsidy inherent in paying demand response providers LMP. Moreover, such a payment scheme could uneconomically reduce real-time prices thereby hindering the introduction of other technologies that could also further the Commission's goals of lowering wholesale energy costs, mitigating market power and supporting system reliability.

> [W]hether payment of LMP should apply to all hours, and, if not, the criteria that should be used for establishing the hours when LMP should apply;

Provided that demand reduction is properly compensated, either through LMP-G or some variant thereof, there is no reason not to schedule such reductions whenever the energy bid provided by the demand reduction provider is economic. It will be critically important, however, to develop criteria, baselines, and measures of actual performance to ensure that realized demand reductions would not have happened but for the provider's response to the compensation opportunity.

> [W]hether requiring payment of LMP is appropriate across all ISOs and RTOs, or whether variations among ISOs and RTOs justify varying levels of de-

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[12] As the NYISO will demonstrate in Part II, however, compensation for demand reduction at LMP-G *is comparable* to compensating generation supply at LMP.

mand response resource compensation [and]

[W]hether the Commission should allow regional variations for an ISO or RTO that does not seek to compensate demand response resources participating in the organized wholesale energy market.

Implementation of LMP-G as the appropriate demand response compensation will require regional variations, including the development by individual ISO/RTOs of the "G" in LMP-G—that is the portion of the retail rate (or proxy thereof) to be reflected in the rate paid for demand response.

As well, demand response compensation needs to be integrated with these existing rules and designs to avoid unintended consequences. As a general matter, market rules have evolved based upon specific ISO/RTO needs (e.g., prevalence of combustion turbine technology, penetration of wind-power, interest of alternative supply resources such as limited energy storage devices). Specific rules act together in market designs to simultaneously address these needs. If, the Commission cannot support LMP-G, it should instead require each ISO/RTO to address the issue of appropriate compensation individually.

III. IN ORGANIZED MARKETS, THE VALUE OF DEMAND REDUCTION FOR COMPENSATION PURPOSES IS NOT EQUIVALENT TO THE VALUE OF INCREMENTAL GENERATION

The Commission defends the use of LMP as appropriate compensation for demand response by stating that it:

> [R]eflects the marginal effect of each demand response resource in the hour; just as LMP reflects the marginal effect of generation resources in each hour. (NOPR at ¶19)

As Professor Hogan points out in his White Paper, LMP does reflect the marginal value of demand and generation in some cases.[13] Under economic dispatch, the marginal cost of *meeting* an increment of load is LMP; load pays LMP for what it takes off the system and generation receives LMP for what it puts into the system. When a demand response provider is responding to economic dispatch signals, it will reduce its consumption when LMP is greater than its cost of consuming (as reflected in its bid) a response that is equivalent to a generator responding to economic dispatch by increasing its output when LMP is greater than its cost of producing (as reflected in its bid). For purposes of balancing supply and demand, economic dispatch reflects the equivalent values of demand response and generation when, for any given LMP, it either directs a demand response provider to reduce its MWh load or directs a generator to add MWh to the system.

This equivalency does not extend, however, to justifying an LMP *payment* for demand reduction as the NOPR envisions it. The NOPR's conclusion that LMP reflects the marginal effect of demand response just as LMP reflects the marginal value of generation resources in each hour[14] is flawed. As Professor Hogan explains, if the

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[13] IRC White Paper, *supra* note 2, at 3.

[14] *See* NOPR at P 19.

marginal effect of the two resource types (demand response and generation) were equal, the net change in costs and revenues to the ISO, when deploying one or the other, would also be the same.[15] But the two do not produce an equal net change in costs and revenues when one or the other is deployed.

Professor Hogan's example at p. 3-4 of his paper explains that an ISO/RTO will incur a net loss when paying demand response providers LMP for its megawatts of demand response, whereas it will break even when paying LMP for generation megawatts. Professor Hogan's illustration explains that the marginal effect of two resource types on the system cannot be the same because the net change in costs to the ISO/RTO is not the same.

Professor Hogan also provides an example of the different revenue streams available to a customer connecting a distributed generator ("DG") depending on which side of its meter it chooses as the interconnection point.[16] Installed on the customer's side of the meter, in Professor Hogan's example, DG can act as a load modifier and its output can be sold as demand response. If located on the ISO/RTO side of the meter, DG can act as a generation resource for the ISO/RTO. Professor Hogan uses this example to further illustrate the different marginal effects that demand response and generation (as represented by the DG) have on the system by explaining how their differing impacts influence a customer's decision as

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[15] *See* IRC White Paper, *supra* note 2, at pp 3-4.

[16] *Id.* at pp 5-6.

to which side of the meter to install its DG. As Professor Hogan explains, the fact that customer is not indifferent as to whether its DG acts as a resource in the market or as supporting an offer of demand response further indicates the two resources are not equivalent in their marginal effects.[17]

IV. PAYING LMP FOR DEMAND REDUCTIONS WILL INAPPROPRIATELY IMPOSE COSTS AND CREATE PERVERSE INCENTIVES

Professor Hogan's example[18] that an ISO/RTO does not experience the same net change in costs and revenues when paying LMP to either demand response or generation also illustrates that paying LMP to demand response providers imposes costs on the ISO/RTO that will need to be recovered from the LSE whose customer provided demand response or from all LSEs though a socialized uplift charge. As the NYISO demonstrates in Part V, paying the demand response provider LMP-G, instead, leaves the LSE indifferent as to whether the costs imposed by incremental load are met through demand response or generation. Paying LMP imposes greater costs on LSEs when the ISO/RTO dispatches demand response than when it dispatches generation.

Professor Hogan's second example, describing the different market effects that distributed generation can create for a customer depending on which side of the meter

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[17] As the NYISO will demonstrate in Part V, however, compensation for demand reduction at LMP-G *is comparable* to compensating generation supply at LMP.

[18] *See* IRC White Paper, *supra* note 2, at pp 3-4.

the DG is located,[19] also serves to explain a potentially significant, perverse incentive to paying LMP for demand response if the Commission were to adopt the NOPR's approach. As Professor Hogan explains, a customer locating its DG on its side of the meter could use the output of the generator to reduce its consumption (perhaps by switching load from the grid to its DG) and could also sell the MWh of demand reduction (metered as the output of its DG) to the ISO/RTO as a demand response resource. This would allow the customer essentially to use the output of its DG both to continue processing at its previous level and to sell the 6 MWh of "demand response" to the grid.

On the other hand, a customer selling its demand response (*i.e.* DG output) for LMP-G would experience net charges similar (depending on the size of the proxy) to those it would have experienced had it received LMP for its demand response (metered as the output of its DG) but also been charged the retail rate for the "demand response" it provided the ISO/RTO. The market effects of locating the meter on either side of the demarcation between retail and wholesale entities would be far less pronounced, if present at all, if the customer was paid LMP-G for its demand response.

Finally, again as Professor Hogan also noted, paying demand response providers full LMP may create an incentive for such customers to avoid moving to retail

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[19] *Id.* at pp 5-6.

dynamic pricing—the preferable rate structure for recognizing the economic value of load vis a vis generation.[20]

V. A MORE APPROPRIATE PAYMENT FOR DEMAND RESPONSE IN THE ENERGY MARKET IS LMP-G

If the Commission determines that retail rates (in areas without dynamic retail pricing) fail to provide efficient incentives for demand response and that wholesale market incentives are necessary to encourage more demand response investment, a more appropriate compensation mechanism than the one proposed in the NOPR should be adopted. The NYISO agrees with Professor Hogan's determination that a more appropriate design would avoid the "unintended consequences of upsetting the principle of equal treatment of equivalent resources" that paying full LMP would entail.

A compensation mechanism built around LMP-G, or the payment of LMP minus the generation component of the retail rate (or a proxy thereof), would result in more economically efficient outcomes, avoid the incremental revenue losses that need to be recovered through uplift that are inherent in paying LMP, and leave LSEs indifferent as to whether increments of load are met with demand response or additional generation.[21] As Commis-

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[20] *Id.* at p 7.

[21] As is discussed more completely in Part VII, below, the choice of which retail costs to include in "G" should be made in individual ISO/RTO proceedings where retail rate structures can be identified and proxy charges developed. Those rate structures that include periodic adjustment clauses for distribution and transmission costs

sioner Moeller noted in his dissent to this NOPR, the concept of paying LMP-G received considerable support and "conservatively could be said to have garnered at least a three-quarters majority approval" in a recent PJM proceeding.[22]

Professor Hogan demonstrates that only a design that pays LMP-G for demand response remains faithful to the efficiency and equal treatment principles of organized markets and sends the correct incentives to market participants.[23] He explains that only by paying LMP-G for demand response will the ISO/RTOs be able to approximate the efficient outcome otherwise produced when dynamic retail pricing exposes all customers to the marginal cost of generation.[24] The NYISO agrees with Professor Hogan that *requiring* ISO/RTOs to pay LMP sends the wrong incentive and is inconsistent with the principles of the organized markets.

Paying LMP-G for demand response leaves the LSEs relatively indifferent as to whether demand response or generation is dispatched to meet their load. The LSE is

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so that the rate structure does not act at cross-purposes with demand response investments may allow the "G" to reflect only the generation component of the retail rate.

[22] NOPR at dissent p 4 n. 11 (Moeller, Comm'r., *concurring in part, dissenting in part*), *quoting PJM Interconnection, L.L.C.*, Docket No. EL09-68-000, Supplemental Report and Submittal of PJM Interconnection, L.L.C. In Support of Further Commission Action on Rehearing, at 24-25 (filed August 26, 2009).

[23] IRC White Paper, *supra* note 2, at p 6.

[24] *Id.* at pp 6-7.

able to recover from its customers the cost of one MWh of generation, at LMP, or one MWh of demand response, priced at LMP-G, by imposing approximately the same unit rate per megawatt consumed.[25] That is, when the LSE collects the cost of the LMP paid for the additional generation its customers used, it has the metered load of all its customers from which to recover this amount. When collecting the cost of paying LMP-G for the demand response its customers used, the amount it is recovering is net of approximately what the demand response customer would have contributed to the recovery (*e.g.* an amount that is net of the contribution of a virtual retail purchase). An LMP-G payment to demand response providers leaves LSEs and their customers relatively indifferent to whether they are charged for generation or for demand response.

VI. PAYING FULL LMP TO DEMAND RESPONSE PROVIDERS IS AN INAPPROPRIATE SUBSIDY THAT MAY NOT FURTHER THE COMMISSION'S POLICY GOALS, INCLUDING HAVING MARKETS THAT PRODUCE LOWER WHOLESALE POWER COSTS.

LMP-supporters that acknowledge that a payment for demand response of full LMP leaves other customers with additional costs have characterized this [extra payment] as a subsidy or a "short-term incentive

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[25] As noted earlier, in retail jurisdictions where the LSE is permitted to charge demand response providers as if they had not reduced their load, a payment of LMP would be appropriate. In those jurisdictions, reflecting in the price paid, the virtual retail purchase of the commodity being sold at wholesale, inherent in LMP-G, is not necessary.

viewed as a form of start-up cost that is needed to help institute [further demand reduction] to provide(s) significant benefits to the entire market." [26] Market-based rates that ostensibly include an uneconomic 'additional payment' as a mechanism to subsidize a favorite technology may be result in preferential treatment and unjust compensation. Subsidies may well be appropriate in some circumstances, but they should be openly described as such and justified.

With respect to this proceeding, paying demand response an LMP-based payment because it is thought that demand response participation will reduce LMPs for all customers is not a sufficient rationale for justifying an 'additional payment' for a favored technology. Demand response is not the only resource able to provide such benefits. Other technologies, with lower costs than traditional generation, can offer LMP-lowering new supply in the same way as can additional demand response. However, such new technologies may be kept out of the market by demand response that would be uneconomic at LMP-G but participates when subsidized at full LMP Without adequate justification, paying LMP to demand response providers may discriminate against other technology providers, or less expensive resources, that are not eligible for the "additional" compensation inherent in LMP. The NYISO agrees with Commissioner Moeller's concern that the Commission has not put forward a "sustainable rationale" to support its conclusion that such a

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[26] *PJM Interconnection, LLC*, 99 FERC ¶ 61,227 at 61,935-36, n.15 (2002).

rule [paying demand response an LMP-based payment] would be just and reasonable and that all other existing compensation mechanisms, approved by the Commission, are no longer just and reasonable.[27]

VII. THE COMMISSION SHOULD ALLOW EACH ISO/RTO TO DEVELOP THE DETAILS NECESSARY TO IMPLEMENT AN LMP-G COMPENSATION PLAN FOR DEMAND RESPONSE PROVIDERS.

If the Commission supports a compensation scheme based on a payment for demand response of LMP-G, it should leave the details of the compensation to individual ISO/RTOs. The NYISO's experience in all of the market areas in which it has integrated demand response reveals that details matter. Programs to promote demand response in wholesale energy markets must incorporate properly calculated compensation in a manner that creates or maintains an integrated and cohesive set of market rules. Indeed, a menu of market design solutions for real-time demand response, created ISO by ISO, may be more productive in influencing demand response providers to enter the energy market than a single ISO/RTO-wide compensation mechanism. Some of the program designs that can provide value in addition to proper compensation include minimum run times, aggregation opportunities, bid protections, new communication opportunities built around smart grid options and scheduling options (*i.e.* 5 or 15 minute flexible schedules).

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[27] *See* NOPR at dissent p 3-4 (Moeller, Comm'r., *concurring in part, dissenting in part*).

If the Commission cannot support LMP-G, it should instead require ISO/RTOs to address barriers in their current market designs that hinder further demand response including the design of compensation appropriate for their jurisdiction.

VIII. CONCLUSION

The New York Independent System Operator, Inc. respectfully requests that the Commission consider the comments above and act or elect not to take action in accordance with them and the IRC White Paper, which was submitted under separate cover as a joint filing of IRC members in this proceeding and is incorporated herein by reference.

Respectfully submitted,

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UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. RM10-17-000

Demand Response Compensation in Organized
Wholesale Energy Markets

May 13, 2010

NOTICE OF INTERVENTION, COMMENTS AND REQUEST FOR CLARIFICATION OF THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA REGARDING THE PROPOSED RULEMAKING ON DEMAND RESPONSE COMPENSATION IN ORGANIZED WHOLESALE ENERGY MARKETS

UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. RM10-17-000

Demand Response Compensation in Organized
Wholesale Energy Markets

NOTICE OF INTERVENTION, COMMENTS AND REQUEST FOR CLARIFICATION OF THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA REGARDING THE PROPOSED RULEMAKING ON DEMAND RESPONSE COMPENSATION IN ORGANIZED WHOLESALE ENERGY MARKETS

Pursuant to Rules 211 and 214(a)(2) of the Federal Energy Regulatory Commission's ("FERC") Rules of Practice and Procedure the Public Utilities Commission of the State of California ("CPUC") hereby submits its Notice of Intervention and Comments regarding the Proposed Rulemaking on Demand Response Compensation in Organized Wholesale Energy Markets ("NOPR").

I. NOTICE OF INTERVENTION

The CPUC is a constitutionally established agency charged with the responsibility for regulating electric corporations within the State of California. In addition, the CPUC has a statutory mandate to represent

the interests of electric consumers throughout California in proceedings before FERC.

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II. COMMENTS

A. The CPUC Supports the Expansion of Demand Response Opportunities in California's Wholesale and Retail Markets.

On March 18, the FERC issued the instant NOPR regarding the compensation of demand response resources in organized wholesale energy markets. This Rulemaking is one of several proceedings at the FERC regarding the expansion of demand response resources across the nation. FERC Orders 719 and 719-A issued in Docket Nos. RM07-19-000 and AD07–7-000 require Independent System Operators ("ISOs") and Regional Transmission Organizations ("RTOs") to modify their tariffs to allow retail customers to bid demand response directly into their wholesale energy and ancillary services markets, either on their own behalf or through aggregators, if the relevant state or regional authorities do not prohibit such direct bidding.[1] The CPUC actively participated in these proceedings and supported many of the proposals.[2] On October 28, 2009, the FERC Staff issued *The National Action Plan on Demand*

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[1] *Wholesale Competition in Regions with Organized Electric Markets* (FERC Order 719), issued on October 17, 2008, in Docket Nos. RM07-19 and AD07-7, available at http://elibrary.ferc.gov/idmws/file_list.asp?document_id=13656106; and *Wholesale Competition in Regions with Organized Electric Markets* (Order 719-A), issued on July 16, 2009 in Docket No. RM07-19, available at http://www.ferc.gov/whats-new/comm-meet/2009/071609/E-1.pdf.

[2] *Comments Of The Public Utilities Commission Of The State Of California*, filed in FERC Docket No. RM07-19 on April 21, 2008.

Response: A Discussion Draft ("National Action Plan").[3] The CPUC submitted generally supportive comments regarding the National Action Plan, especially with regard to collection and dissemination of demand response information to the various and diverse markets across the United States.[4]

Meanwhile, California has taken a leadership role in expanding the supply and functionality of demand response in the State's short-term and long-term energy supply in part through its Energy Action Plan.[5] In California, energy efficiency and demand response are the top two preferred resources in the "loading order" set forth in the Energy Action Plan. Under the Energy Action Plan, California plans to meet energy needs by investing first in energy efficiency and demand side resources, followed by renewable resources, and only then in clean conventional electricity supply. In 2002, California set a goal of replacing 5% of peak demand with price responsive demand response by 2007.

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[3] The National Action Plan can be found at http://www.ferc.gov/EventCalendar/Files/20091028124306-AD09-10-000-Discussion.pdf.

[4] *Notice Of Intervention And Comments Of The California Public Utilities Commission On The Federal Energy Regulatory Commission Staff Draft Proposal On Possible Elements Of A National Action Plan On Demand Response*, (CPUC Comments on National Action Plan) submitted in FERC Docket No. AD09-10 on December 4, 2009.

[5] Energy Action Plan, 2008 Update, issued February of 2008, available at http://www.cpuc.ca.gov/NR/rdonlyres/58ADCD6A-7FE6-4B32-8C70-7C85CB31EBE7/0/2008_EAP_UPDATE.PDF.

The CPUC continues to work collaboratively with the California Independent System Operator ("CAISO") to expand the role of demand response resources in California.[6] The CPUC is an active participant, and generally supported the CAISO's filing in FERC Docket Number ER10-765, in which the CAISO is seeking to comply with Orders 719 and 719-A by developing programs to allow direct bidding of retail demand response load into CAISO wholesale markets. The CPUC also has an ongoing proceeding, Rulemaking 07-01-041, to transition portions of California's existing demand response programs to better integrate such resources with the CAISO's new Locational Marginal Pricing based market and to consider various legal and technical issues arising from FERC Orders 719 and 719-A.[7]

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[6] See *Notice of Intervention And Comments of the California Public Utilities Commission Regarding California Independent System Operator's February*, filed in FERC Docket No. ER10-765 on March 9, 2010, generally supporting the CAISO's Proxy Demand Resource product, which would allow retail customers to bid their demand response resources directly in to the CAISO's wholesale markets. 16th, 2010, Filing Regarding Proxy Demand Resource Product

[7] *Assigned Commissioner And Administrative Law Judges' Ruling Amending Scoping Memo, Establishing a Direct Participation Phase of This Proceeding, and Requesting Comment on Direct Participation of Retail Demand Response in CAISO Electricity Markets*, (CPUC Assigned Commissioner's Ruling on DR) issued in Rulemaking (R.) 07-01-041on November 9, 2009, available at http://docs.cpuc.ca.gov/cyberdocs/Libraries/WEBPUB/Common/searchResultsdsp.asp?pagenumber=1&FT=false&fromQSearch=yes&desc=Detailed+Search.

The CPUC continues to integrate demand side management strategies to maximize the load reductions and/or load smoothing services that these resources can provide. The California Long-Term Energy Efficiency Strategic Plan[8] includes a vision to provide customers integrated demand side solutions, including distributed generation, energy conservation, energy efficiency and demand response. The goal of integration supports California's carbon reduction goals, as well as water and other resource conservation goals. Under utility-administered advance metering programs approved by the CPUC, retail electric customers will have advanced interval meters by 2012, which, coupled with dynamic retail rates, should eventually encourage Californians to reduce their usage during peak hours.[9]

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[8] *California Long Term Energy Efficiency Strategic Plan*, issued September 2008, available at www.CaliforniaEnergyEfficiency.com.

[9] The Legislative Counsel's Digest of California Senate Bill 695, chaptered on October 11, 2009, reads in part, "This bill would prohibit the commission from requiring or permitting an electrical corporation to do any of the following: (A) employ mandatory or default time-variant pricing, as defined, with or without bill protection, as defined, for residential customers prior to January 1, 2013, (B) employ mandatory or default time-variant pricing, without bill protection, for residential customers prior to January 1, 2014, or (C) employ mandatory or default real-time pricing, without bill protection, for residential customers prior to January 1, 2020. The bill would authorize the commission to authorize an electrical corporation to offer residential customers the option of receiving service pursuant to time-variant pricing and to participate in other demand response programs. The bill would require the commission

B. The Proposed "One Size Fits All" Compensation Proposal May Inadvertently Hinder Existing and/or Developing Demand Response Programs.

As a threshold matter, the CPUC notes the diversity among the various ISOs and RTOs; including differences with respect to weather patterns, load shape, and in terms of their development of wholesale and retail demand response programs. The CPUC Staff understands through its discussions with other state regulatory authorities, that there is significant variation between states,' ISOs' and RTOs' development of demand response programs. California's demand response market has developed differently than many of the Eastern markets.[10] Thus, it is unclear whether the NOPR provides an adequate record from which to conclude that the proposed payment method is the only just and reasonable compensation structure across all ISOs, RTO's states, regions, and local regulatory authority zones.

FERC now proposes a national rule that demand response resources be uniformly paid the full Locational Marginal Price for energy in all hours. However, promulgating a uniform national rule at this time

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to only approve an electrical corporation's use of default time-variant pricing for residential customers, beginning January 1, 2014, if those residential customers have the option to not receive service pursuant to time-variant pricing and incur no additional charges, as specified, as a result of the exercise of that option. The bill would exempt certain customers from being subject to default time-variant pricing." Complete statutory language is available at http://www.leginfo.ca.gov/pub/09-10/bill/sen/sb_0651-0700/sb_695_bill_20091011_chaptered.html.

[10] CPUC Comments on Wholesale Markets at pp. 7-8.

may inadvertently impede the implementation of the optimal demand response compensation for an individual ISO or RTO which addresses the needs of that particular region. Additionally, would the FERC's proposed payment method bar the use of Custom Load Aggregation Points proposed in the CAISO's Proxy Demand Resource tariff filing?[11] A mandatory "one size fits all" pricing system may stifle the National Action Plan's efforts to collect valuable data and experience regarding the effects of different demand response program designs upon consumer participation.[12]

The CPUC does not here take a position on the wisdom of the instant proposal that all ISOs and RTOs shall pay demand response providers the market price for energy for such reductions for a variety of reasons. California's existing and proposed retail and wholesale demand response programs are currently being developed and modified in pending CPUC and CAISO/FERC proceedings, and the outcomes of developments are not yet finalized. Additionally, the CPUC is concerned that mandatory "one size fits all" pricing may stifle national and regional efforts to collect valuable data and experience regarding the effects of different

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[11] *CAISO Tariff Amendment to Implement Proxy Demand Resource Product*, filed on February 16, 2010 in FERC Docket No. ER10-765.

[12] See, also *Notice of Intervention and Comments of CPUC under RM07-19 and AD07-7*, filed September 14, 2007, p. 3 (CPUC Comments on Wholesale Markets).

demand response program designs on consumer participation and conflict with Congressional objectives.

As the FERC observed in the NOPR, "ISOs and RTOs have continued to examine the effectiveness of demand response compensation in their respective regions, and as a result, the issue of proper compensation continues to be the subject of several proceedings."[13] Although not specifically referenced for this point, this presumably includes the National Action Plan. In the Energy Independence and Security Act, Congress lists three primary objectives for a National Action Plan:

> (1) Identification of requirements for technical assistance to States to allow them to maximize the amount of demand response resources that can be developed and deployed.
>
> (2) Identification and design of requirements for implementation of a national communications program that includes broad based customer education and support.
>
> (3) Development or identification of analytical tools, information, model regulatory provisions, model contracts, and other support materials for use by customers, States, utilities and demand response providers.[14]

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[13] NOPR at pp. 9-10.

[14] Pub. L. No. 110-140, § 529, 121 Stat. 1492, 1664 (2007) (to be codified at National Energy Conservation Policy Act, 42 U.S.C. §§ 8241, 8279).

As the CPUC stated in its comments on the National Action Plan, "Implementation of the[National Action Plan] is likely to gather and disseminate important information and tools so that states and localities that are leaders in demand response may continue to develop new tools, while those states and localities that are less advanced may obtain assistance in expanding their demand response programs expeditiously and in a manner consistent with their existing local procurement organizations, programs and circumstances. The NOPR's proposal to set a "one size fits all" compensation structure across all ISOs and RTOs seems, however, to potentially conflict with the goals of the Congressionally-mandated National Action Plan to collect and disseminate information regarding diverse programs in order to help ISOs, RTOs, states and local regulatory authorities experiment and examine the effects of diverse market designs on maximizing customer participation.

Similarly, Commissioner Moeller's statement on the NOPR concurring, in part and dissenting, in part; observes that the NOPR's proposal to pay all demand response resources the Locational Marginal Price for energy reductions in all 8,760 hours of the year in all ISOs and RTOs across the nation "is followed by questions such as whether other compensation designs could also work[.]"[15] Thus, the instant NOPR may suggest one particular outcome of the manyfactual,

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[15] Concurrence, in part and dissent, in part of FERC Commissioner Moeller to the NOPR, Issued on March 18, 2010 in Docket Nos. RM10-17 and EL09-68 at p. 2.

legal and policy analyses envisioned in the FERC's concurrent National Action Plan proceeding. As further observed by Commissioner Moeller, the NOPR may be interpreted to direct that "PJM and the other RTOs must now refrain from making changes to [their] demand response compensation rules pending the outcome of the [NOPR]."[16] As the CPUC stated previously with respect to the FERC's efforts to facilitate the expansion of demand response throughout the nation, "[t]he CPUC stresses the importance of allowing the RTOs or ISOs flexibility to modify requirements in the future, as experience is gained with demand response programs."[17] The CPUC therefore reiterates its support for the methods suggested in the National Action Plan to collect, analyze and disseminate information regarding the nation's diverse demand response programs so that states, local regulatory authorities, ISOs and RTOs may use this information to improve the variety and effectiveness of existing and future demand resources.

C. The CPUC Seeks Clarification Regarding the NOPR's Effects Upon State and Federal Jurisdiction Over Retail Ratemaking and Procurement Authority.

Regarding the FERC's National Action Plan, the CPUC expressed its appreciation of "the FERC's recognition of state authority over demand response program design so that states can continue to innovate new strategies and

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[16] *Ibid.*

[17] CPUC Comments on Wholesale Markets at p. 10.

technologies."[18] California recently codified state Senate Bill 695,[19] which limits the timing for implementation of time-variant pricing for California retail electric customers. The CPUC therefore seeks clarification that the FERC does not seek in the instant NOPR to regulate retail consumer rates or Load Serving Entity oversight, roles traditionally exercised by States. For example, is the FERC suggesting that for the purpose of retail revenue settlements or ratemaking, would retail customers would have to be paid the wholesale LMP for their demand response participation, whether positive or negative? The CAISO's Proxy Demand Resource tariff filing reflects its understanding that such settlement systems are within the authority of the CPUC.[20] The CPUC has a pending proceeding which will address systems between demand response aggregators and Load Serving Entities, including whether to account for the alleged "missing money" which may arise if a Load Serving Entity may have paid for generation to supply load that is eventually dropped through a third party demand response aggregator service.[21] The CPUC therefore seeks clarification that the FERC does not intend to alter this balance of state and federal authority.

III. CONCLUSION

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[18] CPUC Comments on National Action Plan at p. 32.

[19] Complete statutory language is available at http://www.leginfo.ca.gov/pub/09-10/bill/sen/sb_0651-0700/sb_695_bill_20091011_chaptered.html.

[20] *insert cite

[21] CPUC Assigned Commissioner's Ruling on DR at pp. 4-6.

For the foregoing reasons, the CPUC respectfully requests the FERC consider the comments discussed above.

Respectfully submitted,

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May 13, 2010

UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Docket No.: RM10-17-000

DEMAND RESPONSE COMPENSATION IN ORGANIZED WHOLESALE ENERGY MARKETS

May 13, 2010

COMMENTS OF STEEL PRODUCERS

Nucor and Steel Dynamics (collectively "Steel Producers")[1] submit these comments in response to the Notice of Proposed Rulemaking ("NOPR") on demand response compensation in organized wholesale energy markets, issued by the Federal Energy Regulatory Commission ("FERC" or "Commission") on March 18, 2010.[2]

I. INTRODUCTION

Steel Producers produce steel using a recycling process that employs electric arc furnaces ("EAFs"). EAF steel-making is vastly more energy efficient than the traditional integrated steel-making process.

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[1] These comments are filed on behalf of the Steel Producers' mills that are located in the footprints of PJM and/or the Midwest ISO.

[2] Demand Response Compensation in Organized Wholesale Energy Markets, 75 Fed. Reg. 15,362 (March 29, 2010).

Nevertheless, EAFs consume large amounts of energy in the process of melting and recycling scrap steel. The cost and availability of electricity are central to the economics of Steel Producers' operations.

Steel Producers commend the Commission for issuing this NOPR and proposing to increase the compensation paid for demand response. Steel Producers believe that the Commission's proposal is a good first step. However, in order to more adequately incentivize demand response, the Commission should adopt a rule that compensates demand response at a level higher than LMP (i.e., "LMP Plus"). In the alternative, the Commission should proceed with compensation at full LMP while initiating a study of the costs and benefits of paying LMP Plus. Steel Producers' comments are summarized below:

- Compensation for demand response should recognize the unique benefits that demand response provides, and it should provide an adequate incentive for load to elect to act as demand response. Demand resources should be paid compensation that exceeds full LMP (i.e., "LMP Plus").
- In addition to the typical "voluntary" economic demand response program, RTOs and ISOs should be required to establish a "mandatory curtailment" economic demand response program, in which load that elects to participate commits to curtail when the RTO exercises its discretion to call for economics-based curtailments (i.e., mandatory curtailments called by the RTO based on LMP).

II. COMMENTS

Demand response is critical to well-functioning electricity markets, and the benefits of demand response are far-reaching.[3] As the Commission recognizes, demand response can: (i) improve the functioning and competitiveness of electricity markets in several ways, including by lowering prices; (ii) support system reliability and address resource adequacy; and (iii) reduce the potential for market manipulation by reducing generator market power.[4] This list of benefits is by no means exhaustive. Moreover, national policy requires facilitation of demand response.[5] As the Commission explores ways to adequately compensate demand response in the organized markets, the Commission should ensure that it does not discourage traditional retail demand response programs such as interruptible rates, or innovative new retail demand response approaches. In fact, the Commission notes that the scope of this rulemaking is confined to demand response providers participating as resources in the day-ahead and real-time energy markets.[6] In short, the Commission should ensure that its demand response policies at the federal level complement, rather than alter or displace, successful state-level demand response opportunities.

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[3] *See* NOPR at P 5.

[4] *See id.* at P 3-4.

[5] *See id.* at P 5.

[6] *See id.* at P 7.

The Commission recognizes that demand response can reduce the need to dispatch high-priced generation and construct new generation.[7] In addition to the obvious savings associated with such avoided costs, demand response should be of particular interest to policymakers and the public, given: (i) the need to meet the rapidly increasing demand for electricity, (ii) the resistance to new generation and transmission infrastructure at the state and local levels, and (iii) heightened environmental concerns about the energy industry. By increasing available capacity while reducing the need for expensive and sometimes controversial new capital projects, demand response is uniquely suited to reconciling these competing interests.

Although there is near universal recognition of the benefits and importance of demand response, participation by demand response in the markets remain far below the levels necessary to ensure properly functioning electricity markets. The Commission should is rightly concerned that inadequate compensation structures have hindered the development and use of demand response.[8] Steel Producers have often commented that existing RTO compensation structures for demand response are inadequate.[9] Steel Producers

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[7] *See* NOPR at P 4.

[8] *See id.* at P 9.

[9] *See e.g.*, Comments of Steel Producers, Docket No. RM07-19-000 (September 14, 2007) (stating the Commission should consider ways of providing additional compensation to demand response resources in recognition of the system-wide benefits

are of the opinion that while the compensation proposed in the NOPR (i.e., full LMP) is an improvement, it remains insufficient and will not adequately motivate demand response. The Commission should ensure that its policies lead to strong and sustained levels of demand response.

1. Demand Resources Participating in RTO/ISO Markets Should be Paid "LMP Plus."

The Commission seeks comments on the appropriate level of compensation for economic demand response.[10] In order to provide an adequate incentive for potential demand response, and to fairly compensate customers for the benefits their demand response provides, demand response should be paid LMP plus a

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demand response provides, not only energy cost savings, but reliability and environmental benefits as well); Motion to Intervene and Protest of Steel Producers, Docket No. ER06-406 (January 19, 2006) (stating "Steel Producers' principal objection to the economic program as proposed by PJM is that it does not fairly compensate end-users for demand response, and it provides very little incentive for such customers to participate in the program"); Protest of Steel Producers, Docket No. EL09-68-000 (September 16, 2009) (stating that the implementation of a sunset provision will likely result in a substantial decline in demand response settlements and FERC should require that PJM make demand response incentives permanent); Motion to Intervene and Comments of Steel Producers, Docket No. ER03-1118-000 (September 15, 2003) (stating "if LMP is the measure of what an end-user gets paid for demand response, the enduser should also receive a load ratio share of the system benefits that flow from its demand response.").

[10] *See* NOPR at P 20.

share of the system benefits that are a consequence of the demand response.

The benefit that demand response provides to the system in the form of reduced wholesale prices typically far outweighs the cost at full LMP, especially at times of peak demand when demand response does the most to dampen wholesale prices and ensure reliability.[11] In the current environment, most consumers continue to pay retail prices during periods of peak power consumption, such prices provide no financial incentive to curtail consumption during peak periods. This results in inelastic demand even as spot power prices rise dramatically.[12] In contrast to more typical elastic markets, the lack of broad demand response results in excessive prices during peak periods. To reduce this burden, the Commission should afford demand response a share of the benefits that arise as a direct result of demand response. Such an incentive would result in greater demand side participation, which would reduce the marginal cost of generation.

Compensating large industrial customers at full LMP does not provide an adequate incentive for those large customers to curtail their loads. For example, in PJM's AEP Zone, during 2009 there were zero

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[11] Some studies have estimated the long run system-wide benefits of demand response to be in the billions of dollars per year. *See* e.g., "The Power of Five Percent: How Dynamic Pricing Can Save $35 Billion in Electricity Costs," the Brattle Group, May 16, 2007.

[12] *See* Quantifying Demand Response Benefits in PJM, The Brattle Group at p. 20 (January 29, 2007).

hours during which LMP surpassed $200. In other years, there have been very few hours that have exceeded $200:

PJM AEP Zone Number of Hours LMP Surpassed Given Price in a Given Year							
	2004	2005	2006	2007	2008	2009	2010 (through 2-28-10)
LMP > $200 MWh	0	11	27	15	15	0	2
LMP > $300 MWh	0	0	8	1	2	0	0

During these limited hours, a large industrial customer with 50 MW of interruptible load would receive a relatively small payment to shut down its production. This payment would be offset by shutdown costs and other costs such as lost margin experienced as a result of the curtailment. It is important that customers, especially those with large loads, receive an adequate incentive to act as demand response resources. The Commission notes what is intuitively correct, that demand response resources react correspondingly to increases or decreases in payment.[13] As shown below in Figure 1, when LMP is low there is very little demand response.[14]

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[13] *See* NOPR at P 10 (using PJM's reduction of demand response compensation as an example of this point, citing Monitoring Analytics, Barriers to Demand Side Response in PJM at 22 (July 1, 2009)).

[14] *See* Walawalkar, Blumsack, Apt, Fernands, "An Economic Welfare Analysis of Demand Response in the PJM Electricity Market," Carnegie Mellon Electricity Industry Center Working Paper, CEIC-07-13 (citing Covino, S., 2006. PJM Economic Load

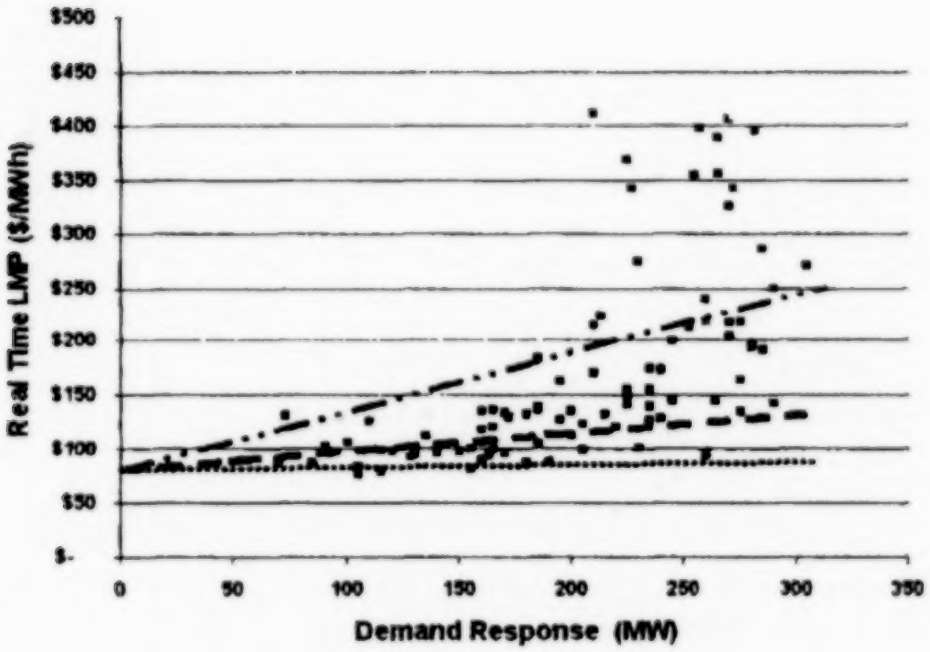

Figure 1 Load curtailment data from PJM's economic demand response market during six days in 2006.

As LMP increases, so does demand response.[15]

When it has been present, demand response has provided enormous system-wide benefits. For example, PJM reported that demand reductions during August 2006 produced $650 million in system energy savings.[16] This system-wide benefit was distributed

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Response: Summer 2006 Potential and Performance, a presentation to the Demand Side Response Working Group, November 2006).

[15] *See id.* at 8 ("The most significant factor in the decision to bid DR is the expectation of the market-clearing price in PJM").

[16] *See* PJM News Release, "Early Aug. Demand Response Produces $650 Million Savings in PJM" (August 17, 2006) ("PJM News Release").

to all customers through a reduction in LMP.[17] However, demand response participants were paid roughly $5 million, or less than 1% of the total system savings.[18]

As this PJM example demonstrates, demand response greatly benefits nonparticipating customers. The total system savings generated by demand response, and the impact of an enhanced volume of demand response, fully justify paying demand response LMP Plus (i.e., LMP plus a share of the total system savings).[19] The savings generated by demand response may be calculated by running a shadow "but for the demand response" LMP for comparison to the actual LMP. A simple example is illustrative of the system benefits derived from demand response. Suppose a system has total load of 1,000 MW, of which 100

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[17] PJM is one of several RTO's that relied on demand response to mitigate the impact of the record level of peak demand in the Summer of 2006. *See* Hopper, Goldman, Bharvirkar and Engel, "The Summer of 2006: A Milestone in the Ongoing Maturation of Demand Response." LBNL-62754 (Lawrence Berkeley National Laboratory, May 2007) ("[T]he unexpectedly high peak demands threatened grid operators' abilities to maintain system reliability. DR resources were called on to alleviate these conditions").

[18] *See* PJM News Release.

[19] Customers on LMP based contracts should continue to receive their shutdown costs. *See* PJM FERC Open Access and Transmission Tariff, Six Revised Volume No. 1, Second Revised Sheet No. 388E. It is important to pay shutdown costs otherwise the net benefit of the curtailment (LMP Plus, less shutdown costs) may be too small to interest large industrial customers with curtailable loads.

MW is capable of acting as demand response. Also suppose that the impact of the demand response is that LMP is $100/MWh rather than $150/MWh, the system benefit from the demand response is $50 per MWh. The load that does not act as demand response receives the benefits caused by the demand response through the depressed LMP—the 900 MW of static load on the system receives a benefit of $45,000 per hour (i.e., 900 MW* $50/MWh). If this benefit is realized over the course of three peak hours, the total system benefit from the demand response is $135,000. Under the proposed Commission approach, the demand response would be paid LMP ($100/MWh) for curtailing. So the 100 MW of demand response would be paid a total of $30,000 for the three hours of curtailing (i.e., $10,000 per hour for three hours). The net system benefit of the demand response would be $105,000 for those three hours. In order to incentivize more demand response, to further reduce system costs, the Commission should structure a compensation plan that allows demand response to share in those net system benefits.[20] This example, although simplified,[21] is consistent with PJM's past experience, discussed above, and demonstrates that the cost sav-

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[20] For example, the demand response could be paid a "share" of the system benefits.

[21] The example does not take into account shutdown costs or opportunity costs for demand response, nor does it include the environmental and reliability benefits that demand response supplies to the system. These omitted details all further imply that demand response should receive a larger incentive for curtailing—namely LMP Plus rather than full LMP.

ings generated by demand response far exceeds its cost and warrants an additional incentive.

Large industrial loads, like Steel Producers', do not exist to produce energy or capacity. They exist to produce steel. Shutting down a steel production process is expensive—not only does the producer incur the physical costs associated with shutting down and starting up, but the producer incurs opportunity costs. In an effort to capture the value of demand response, the Commission should afford demand response a share of the system benefits.[22] Payment of "LMP Plus" will result in additional demand response and greater system and societal benefits in the form of (a) lower LMPs, (b) enhanced reliability, (c) market power mitigation, and (d) environmental benefits. Accordingly, compensating demand response by paying more than LMP is both sensible, because it provides a more appropriate price signal to demand response thereby resulting in additional demand response and associated value, and equitable, because demand response deserves to receive a share of the system benefits that it generates.

2. The Commission Should Require Mandatory Economic Demand Response Programs That Provide for an Option Payment.

The Commission should encourage a "mandatory curtailment" economic demand response alternative where end-users would be *required* to curtail for eco-

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[22] At the very least, the Commission should study the effects of compensating demand response at LMP Plus rather than full LMP.

nomic reasons, if called upon to do so by the RTO. Under the "voluntary" economic demand response programs in existence today, end-users decide based on real-time economics whether and when to curtail. An end-user participating in an economic demand response program is typically under no obligation to curtail for economic reasons, and there is no penalty for choosing not to curtail. Under a mandatory economic program, the end-user receives an advance option payment for agreeing to curtail when directed to do so by the RTO. The RTO would have the right to call (i.e., a call option) for the curtailment of load at the RTO's discretion. Registration in the program would be voluntary for demand response, however, once registered, registrants would be required to curtail when called upon by the RTO/ISO.[23] Since the RTO/ISO would have the discretion to curtail the demand response within predetermined parameters, the RTO/ISO could rely on performance by the economic demand response, thus giving the RTO/ISO access to a reliable, dispatchable resource. The ability to rely on economic demand response would be particularly useful to the RTO/ISO during periods when LMP is too low to attract voluntary economic demand response. Under a mandatory economic program, the load will be curtailed when the RTO/ISO decides it is optimal for the system that the load curtail, thus maximizing the system-wide benefits of the demand response. Furthermore, a mandatory economic program would add a

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[23] This is in contrast to most economic programs today where the decision to curtail is the end-user's alone.

new demand response product to the list of demand response alternatives that exist in organized markets today, and more product differentiation will likely increase the level of economic demand response participation.

Steel Producers recommend the implementation of a mandatory economic demand response alternative. Steel Producers have years of experience with interruptible load in regulated settings—agreeing to interrupt for a pre-determined number of hours in exchange for compensation. Integrated utilities have often relied on this type of demand response to reduce their cost of service. RTO/ISO's should adopt this form of economic demand response in order to induce demand response that has historically been utilized by utilities to reduce their cost of service. Failing to incorporate this form of demand response would imply a system that lacks a form of demand response that was historically available and consequently a higher cost of service.

III. CONCLUSION

Steel Producers respectfully request that the Commission consider these comments and incorporate the independent concepts of: (i) "LMP Plus"; and (ii) "mandatory economic demand response" in any new rule.

Respectfully submitted,

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May 13, 2010

UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Docket Nos. EL09-68-000, RM10-17-000

DEMAND RESPONSE COMPENSATION IN ORGANIZED WHOLESALE ENERGY MARKETS

May 13, 2010

COMMENTS OF ENERNOC IN RESPONSE TO NOTICE OF PROPOSED RULEMAKING

EnerNOC, Inc. ("EnerNOC") respectfully submits comments in response to the Federal Energy Regulatory Commission's ("FERC" or "Commission") Notice of Proposed Rulemaking ("NOPR") published in the Federal Register on March 29, 2010.[1] EnerNOC fully supports the proposed rule in the NOPR, and respectfully requests that the Commission adopt the proposal as a final rule.

I. Introduction

EnerNOC[2] was a party and participant in FERC Docket No. ER09-68-000, which docket was terminated

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[1] Demand Response Compensation in Organized Wholesale Energy Markets, 75 Fed. Reg. 15,362; 130 FERC ¶ 61,213 (2010) (*hereinafter* "NOPR Order").

[2] EnerNOC, Inc. is an Aggregator of Retail Customers that provides demand response and energy efficiency services, among other offerings, in both wholesale and bilateral markets throughout North

with the issuance of the NOPR. Though no final order issued forth from that proceeding, the record therein established that the current mechanism for compensating demand response in the PJM Interconnection, LLC ("PJM") wholesale day ahead and real time energy markets (the wholesale energy price minus the generation and transmission components of the demand response resource's retail rate) was unjust and unreasonable, and that proposed compensation at the full locational marginal price in the wholesale energy market was just and reasonable. The Commission has recognized that the startling decline of participation in demand response in the PJM energy markets may be the result of compensation that is unjust and unreasonable in its failure to reflect the marginal value of demand response resources.[3]

The Commission, recognizing that the issue of proper compensation continues to be an issue in several proceedings across several wholesale markets[4], has determined to address its concerns regarding inadequate compensation in PJM and other wholesale markets in this generic rulemaking proceeding.[5] EnerNOC supports the Commission's approach to address this issue in a consistent fashion through a rulemaking. As the Commission has noted, different and evolving com-

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America and in the United Kingdom. As of March 31, 2010, EnerNOC had more than 4,350 MW of demand response resources under management.

[3] NOPR Order at ¶ 10.

[4] NOPR Order at ¶ 8.

[5] NOPR Order at ¶ 23.

pensation structures for demand response have become a barrier to the development of demand response resources.[6] The instant NOPR presents the Commission with the opportunity to remove yet another barrier and establish just and reasonable compensation for demand response in wholesale energy markets.

EnerNOC is part of several coalitions from throughout the United States submitting comments in these dockets, including comments from the Consumer Demand Response Initiative, Demand Response Supporters, Demand Response and Smart Grid Coalition, and the Price Responsive Load Coalition. EnerNOC fully supports the comments submitted by these coalitions, and submits separate comments to expand upon a few of the areas in which the Commission seeks comment.

II. Brief Summary Comments on the NOPR

Current compensation to demand response in organized wholesale markets is inadequate and undervalues demand response as a resource. As a result of market rules in RTOs/ISOs that do not compensate demand response commensurate with its value, demand response is grossly underdeveloped in wholesale energy markets. We have witnessed incredible innovations in technology and measurement and verification in the last decade that makes it possible to do so much more toward market efficiency with demand response resources. Despite this progress, meaning-

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[6] NOPR Order at ¶9.

ful demand response participation in wholesale energy markets has failed to materialize. In light of this market failure, where we have the ability and means to improve market efficiency and lower prices to customers well within our grasp, prices in wholesale energy markets can no longer be said to be just and reasonable.

The alternative approaches to demand response compensation, all of which have failed to promote market efficiency, all suffer from the same basic problem—they don't compensate demand response for the value it brings to the wholesale market. There is only one price for energy in a wholesale market at a given time and location. That price reflects the value to the market of an increment of supply or decrement of demand. The "LMP minus components of the retail rate" mechanism systematically undervalues demand response. Another approach is to compensate demand response fairly only during very high priced hours under very restrictive conditions. This has proven effective at creating a non-opportunity for demand response. What looks like an opportunity may exist on paper in a tariff, but it is no opportunity at all in the real world.

The Commission is exactly correct to unify its policy around the single principle that there is a single market price in the wholesale markets for all resource types, and it is appropriate to codify that principle in federal regulation. To the extent that regional variations are designed to accommodate a regulation under

different market designs embodied in FERC-approved tariffs, they may be acceptable. But what should not be tolerated is going beyond implementing the rule by enabling regional variations that would undermine the intent behind the rule.

Organized markets are still evolving, and will do so for the foreseeable future. The NOPR reflects the reality today that demand response is underdeveloped in energy markets. The NOPR seeks to address the problem directly, and move markets in a positive direction toward greater market efficiency. When those that do not support paying demand response adequate compensation worry about the future, they worry about a world in which there is too much demand response—and therefore urge FERC not to take steps to improve the *status quo*. A world with too much demand response is not the world we live in today, and it won't be that way tomorrow. Over time, innovations not yet imaginable will create a new set of worries and opportunities, and a whole new set of different issues. A periodic review of demand response compensation in the context of a comprehensive analysis of how wholesale markets are functioning is entirely appropriate; circumstances and assumptions change with the benefit of history. If we have too much demand response in the future, the Commission can do something about that "problem." But a periodic review should not be viewed as a sunset. At such time in the future if the Commission believes circumstances have changed again and its final rule no longer

leads to just and reasonable results, it can make appropriate changes at that time.

A lot of work has been done and will continue to be done in the area of customer baselines to determine the meaning of "expected levels" of consumption. That work will go on and should go on. Indeed, we hope that important work by the North American Energy Standards Board and others will continue to improve baseline integrity. While we encourage continued work on baseline rule enhancements, we would urge the Commission not to delay the final rule while this work goes on.

III. Whether current compensation for demand response providers acting as a resource in the organized wholesale energy markets is adequately procuring demand response.

The current compensation mechanisms in use by FERC jurisdictional regional transmission organizations and independent system operators (RTO/ISOs) are not adequately procuring demand response for the wholesale energy markets. On a more fundamental level, the inadequate compensation mechanisms in place today in wholesale energy markets fail to induce sufficient investment in demand response resource infrastructure and expertise that could lead to adequate levels of demand response procurement. Without sufficient investment in the development of demand response, demand response resources simply cannot be procured because they do not yet exist *as resources*. Such investment will not occur so long as

compensation undervalues demand response resources.

By contrast, appropriate compensation attracts investor capital to enable firms to make appropriate investments to bring demand resources to market. For example, EnerNOC and its competitors have experienced explosive growth in bringing demand response resources in wholesale capacity markets that treat demand response as a supply-side resource and value demand response capacity on a comparable basis to generation capacity. In PJM, demand response capacity has increased fivefold since 2006, and now accounts for 6% of the resources relied upon to meet the PJM system peak.[7]

The dramatic growth in PJM and elsewhere can be directly traced to removing barriers to demand response in the capacity markets and providing comparable treatment, including compensation, for demand response resources to that of generation resources. There is only one price in these markets for capacity resources, regardless of whether the resources are demand response, energy efficiency, or generation.

It is beyond question that getting the rules right in RTO/ISOs with capacity markets facilitated unprecedented growth in demand response capacity resources. This growth was fueled by unprecedented public and

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[7] PJM News Release, *Demand Response to Play Significant Role in Meeting PJM's Higher Summer Peak Electricity Use*, May 5, 2010, (http://www.pjm.com/~/media/about-pjm/newsroom/2010-releases/20100505-summer-2010-outlook.ashx).

private capital investment in the demand side resource firms like EnerNOC and others, who in turn made unprecedented infrastructure investments in enabling customers to bring demand response resources to market. With the creation of these capacity markets, with comparable opportunities for demand response resources to compete with generation, it is no exaggeration to state that the Commission created an entirely new industry that had not existed previously.

The story of success of demand response in regions with capacity markets is attenuated by the failure to attract meaningful customer participation and investment in demand response participation in wholesale energy markets. For example in PJM, in January of this year (the highest month of participation thus far in 2010), there were some 160 customers in all of PJM that participated in at least one economic load response event.[8] Meanwhile, as of May 11, 2010, there are in excess of 7,400 unique customers enrolled in the capacity programs for the 2010/11 delivery year.

ISO-NE is another market with robust participation by demand response in its capacity market. Yet participation in ISO-NE's energy market opportunity for demand response is nearly non-existent. The reasons in ISO-NE for grossly anemic participation by demand response in the energy market are slightly

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[8] PJM Load Response Activity Report, January-April 2010; (http://www.pjm.com/markets-and-operations/demand-response/~/media/markets-ops/dsr/2010-dsr-activity-report-20100511.ashx); May 11, 2010.

different than in PJM. ISO-NE has no opportunity for demand response to participate in energy markets for almost all hours of the year, and no opportunity at all for demand response to participate in the real time energy market. ISO-NE has an exceedingly restrictive pilot program-type program that enables demand response to receive full LMP compensation under very narrow circumstances when there are very high-priced hours in the day-ahead market and customers commit to participation on a day-ahead basis. This "opportunity" has failed to attract meaningful participation, even while there is robust participation by demand response in the capacity market.

What is remarkable is that regions with such high penetration of demand response capacity resources can at the same time have such a dearth of participation in energy markets. It does not require a leap of faith to acknowledge that this difference is due to the way the resources are treated in the wholesale market: capacity markets tend to value demand resources on a comparable basis with generation, while energy markets undervalue demand response when compared to generation.

There is no lack of interest on the part of *customers* to participate in demand response in energy markets. While infrastructure and enablement costs and customer education present modest barriers to entry[9], the

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[9] While some of the infrastructure installed to enable participation in a capacity program *may* be able to be utilized for energy market participation, demand response participation in energy markets gen-

primary barrier is regulatory. Energy markets undervalue demand response throughout market rules that either deny it access to markets available to generation, or compensate it at lower levels. Demand response providers cannot justify making significant increases in customer infrastructure investments to enable energy market participation in demand response when the market access is limited and the demand response resource itself is undervalued.

If the inadequate compensation barrier is removed —if the NOPR proposal is adopted as a final rule—and the Commission remains vigilant in removing market access barriers, customer participation will increase as greater capital investment will be attracted to expanded demand side opportunities. The result then, just as spring follows winter, will be more efficient wholesale energy markets.

IV. Whether paying LMP to demand response resources is comparable compensation or is more or less than comparable compensation paid to generation in the ISO and RTO energy markets.

A. Demand response is not a sale for resale.

Some commenters in this NOPR will no doubt advocate for the *status quo* of inadequate demand response compensation that follows a formulation that results in a payment to demand response resources of

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erally requires enhanced infrastructure functionality, enhanced customer education and information needs, and higher opportunity costs for participants.

LMP minus components of the retail rate ("LMP Minus").[10] The rationale behind such formulations rests upon a product definition that considers demand response activity a sale for resale of energy in wholesale markets. The logic goes that the customer must first purchase the energy (at the customer's retail rate) before it can sell the energy at LMP. Therefore, proponents of this view would assert that compensation of LMP Minus is appropriate. This approach fails to hold up to scrutiny in light of recent Commission precedents.

The Commission has expressly distanced itself from such a definition of demand response, and should resist entreaties by opponents of comparable treatment to resurrect it. Following an extensive stakeholder process culminating in the issuance of Order 719[11], the Commission adopted a definition of demand response as follows:

> Demand response means a reduction in the consumption of electric energy by customers from their expected consumption in response to an increase in the price of electric energy or to incentive payments designed to induce lower consumption of electric energy.[12]

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[10] NOPR Order at ¶ 19.

[11] Wholesale Competition in Regions with Organized Electric Markets, Order 719, 73 Fed. Reg. 64,100 (October 28, 2008).

[12] 18 CFR § 35.28(b)(4).

The Commission could have defined demand response as "the purchase of energy by a customer for the purpose of not being consumed." The Commission avoided such an illogical definition in favor of one that is far more sensible. Yet it is this illogical definition that flows from what the proponents of LMP Minus will urge the Commission to adopt. The text of the regulation defies such a tortured definition—thankfully.

Beyond the definition of demand response in Order 719 promulgated by the Commission into federal regulation, the Commission further distanced itself from the "sale for resale" formulation in its EnergyConnect Order earlier this year.[13] The EnergyConnect Order provided guidance to Aggregators of Retail Customers concerning the applicability of Commission requirements to obtain market-based rate authority. The Commission stated that "[W]here an entity is only engaged in the provision of demand response services, and *makes no sales of electric energy for resale*, that entity would not be a public utility." (emphasis supplied).[14] In rejecting the "sale for resale" formulation, the Commission acknowledged that while it had previously characterized purchases of demand reductions as involving a sale for resale, the Commission no longer relies on that characterization. In-

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[13] Order Conditionally Granting Market-Based Rate Authorization and Providing Guidance, FERC Docket No. ER09-1307, 130 FERC ¶ 61,031 (January 19, 2010).

[14] *Id.* at ¶ 30.

stead, the Commission said, it relies upon the definition of demand response in the above-cited regulation.[15]

Demand response is not a commodity sale or resale of energy. Demand response resources need not take title to energy prior to the provision or service of demand response. Contrary to being a commodity sale for resale, demand response is a service, or a "practice" affecting wholesale rates that is subject to the Commission's broad authority under the Federal Power Act.[16]

The curtailment service or practice provided by a demand response resource provides the same value to the grid of adding a new increment of generation supply. This demand response service or practice should be compensated comparably to generation because it provides the same value—and that compensation is the wholesale energy price.

Recent Commission precedents establish that demand response is not a sale for resale of electric energy. It would be inappropriate, therefore, to establish compensation that presumes that demand response is a sale for resale. EnerNOC respectfully requests the Commission reject attempts by opponents of adequate compensation to demand response to give the argument new life.

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[15] *Id.* at ¶ 31.

[16] Wholesale Competition in Regions with Organized Electric Markets, Order 719-A, 128 FERC ¶ 61,059 (July 16, 2009).

B. Subtracting components of the retail rate from LMP results in inefficient dispatch that undervalues demand response.

EnerNOC agrees with the Commission that "[d]emand response can also lower prices in the organized wholesale energy markets by reducing the need to dispatch higher-priced generations, or construct new generations, in an effort to satisfy load."[17] The practice of subtracting components of the retail rate from LMP in wholesale markets leads to a bias in favor of generation resources that undervalues demand response.

Consider a hypothetical in which the LMP is $200/MWh, and a demand response bidder with a retail supply rate of $75/MWh bids a demand response resource at $225/MWh. The demand response resource will not clear the market, and will not be dispatched. This is true although the actual cost to the market would only be $150/MWh to compensate demand response to meet the energy needs of demand on the system (load) that values the incremental supply (or demand response equivalent) at $200/MWh, which is the LMP. Meanwhile, a generator that bid $190/MWh would clear and would be dispatched to serve load and be paid the full LMP at $200/MWh. The value of the resource to the market is $200/MWh, and the resource need can be met by generation or demand response. The offset to LMP for the customer's retail

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[17] NOPR Order at ¶ 4.

rate results in the inefficient dispatch of higher cost generation instead of lower cost demand response.

IV. Conclusion

EnerNOC appreciates this opportunity to submit comments for the record in this Notice of Proposed Rulemaking. The proposal set forth in the NOPR establishes appropriate compensation for demand response participating in wholesale energy markets. EnerNOC respectfully requests that the Commission issue a final rule.

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Dated: May 13, 2010

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UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. RM10-17-000

DEMAND RESPONSE COMPENSATION IN ORGANIZED WHOLESALE ENERGY MARKETS

May 13, 2010

COMMENTS OF ISO NEW ENGLAND INC.

On March 18, 2010, the Federal Energy Regulatory Commission ("Commission") issued a Notice of Proposed Rulemaking on Demand Response Compensation in Organized Wholesale Energy Markets in Docket No. RM10-17-000 ("NOPR"). ISO New England Inc. ("ISO-NE") respectfully submits these comments in response to the NOPR.

I. INTRODUCTION AND EXECUTIVE SUMMARY

In the NOPR, the Commission proposes that:

> Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) with tariff provisions permitting demand response providers to participate as resources in energy markets by reducing consumption of electricity from their *expected levels* in response to price signals be required to pay to demand response providers, *in*

> *all hours, the market price for energy* for such reductions.[1]

Specifically, the Commission proposes that ISOs and RTOs be required to pay demand response providers "the market price for energy, *i.e., full LMP*, for demand reductions made in response to price signals."[2] The Commission reasons that "paying demand response resources the LMP in all hours will compensate those resources in a manner that reflects the marginal value of the resource to each RTO and ISO, comparable to [the] treatment of generation resources."[3]

An efficient wholesale energy market requires active demand participation in which the demand side of the market responds to market-clearing energy prices. To achieve this end, ISO-NE has been working with the New England Power Pool ("NEPOOL") and the New England Conference of Public Utilities Commissioners ("NECPUC") to develop and implement a variety of demand response initiatives that provide financial incentives to demand response providers whose demand resources respond to wholesale energy prices or to system reliability events. New England's experience demonstrates the value of initiating and

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[1] NOPR at P 1 (emphasis added). The NOPR states that this provision would apply only to demand response acting as a resource in organized wholesale energy markets and not to demand response receiving payments to respond in reliability or emergency conditions, or participating in ancillary service markets. NOPR at fn.4 and P 7.

[2] NOPR at P 11 (emphasis added).

[3] NOPR at P 12.

evolving demand response programs. Since the time ISO-NE introduced both Locational Marginal Prices ("LMPs") and a number of demand response initiatives in 2003, the region's demand response capability has grown over 11-fold. Ultimately, ISO-NE's objective is to fully integrate demand resources into the wholesale market. This will improve overall market efficiency and ensure that demand resources compete on a comparable basis with generation resources.

While the NOPR proceeding presents an opportunity to increase the integration of demand resources into the wholesale energy market, the proposed rule will lead to inefficient outcomes in the energy markets unless the Commission addresses these inefficiencies through other means. Paying full LMP to demand resources that have reduced consumption relative to an estimated baseline as required by the proposed rule will encourage the dispatch of higher-cost demand resources that will displace lower-cost generation in the wholesale energy markets. This is inefficient, runs counter to the fundamental least-cost resource dispatch procedure of the energy markets, and will ultimately raise consumer costs. ISO-NE developed these views after careful consideration informed by over 19 months of analysis and discussions with stakeholders and state regulators on the topic of achieving price-responsive demand in New England.

The proposed rule appears to be based on the false assumption that demand resources and generators are equivalent, and that demand response providers should participate in energy markets like generators

by submitting supply offers reflecting the marginal cost of their resource.[4] Demand resources, however, are physically different from generators—demand resources reduce consumption whereas generators serve consumption. Because demand resources reduce consumption, a demand response provider's reaction to energy market price signals will consider savings in the consumer's energy bill plus any incentive payments from the wholesale energy market. By paying the full LMP to demand response providers without taking into account the bill savings produced by demand resources, demand response providers are given a significant financial incentive to dispatch demand resources with marginal costs exceeding LMPs. By dispatching higher-cost demand resources, lower-cost generating resources are displaced, which is inefficient and increases total resource costs in the energy market. In contrast, payment of the full LMP to generators does not produce inefficient results because generators have no bill savings to consider. To efficiently integrate demand resources into wholesale energy markets where all energy resources (generators and

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[4] See NOPR at P 15. "Given that the LMP represents the marginal value of the resource being used by the RTO or ISO to balance supply and demand, it follows that the LMP should be paid to any resource clearing in the RTO's or ISO's energy market. In balancing supply and demand, a one megawatt reduction in demand is equivalent to a one megawatt increase in energy for purposes of meeting load requirements and maintaining a reliable electric system. The ISO or RTO is able to avoid dispatching suppliers with higher bids, be they generation or demand response, by accepting a lower bid to either reduce consumption or increase generation."

demand resources) are economically dispatched in order of increasing marginal costs, the financial incentives provided to demand resources must be made comparable and symmetric to the financial incentives provided to generation resources. Comparability and symmetry are achieved by netting out the bill savings from the full LMP payment made to a demand response provider for demand reductions, for demand resources that have reduced consumption relative to an estimated baseline.

Further, the proposed rule appears to be based on the notion that the goal of demand resource participation in the energy market is to produce the lowest LMPs.[5] While such a notion may be appealing from a short-term cost perspective, demand resource participation in energy markets should serve a greater purpose—that is, to contribute to a more reliable electrical energy system at the lowest total resource cost. The use of demand resources to achieve a least-cost electrical energy system is consistent with cost-effectiveness principles that have been developed and used by the states over the past three decades to guide

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[5] *See* NOPR at P 4. "Demand response acting as a resource in organized wholesale energy markets helps to improve the functioning and competitiveness of such markets in several ways. *First, demand response can lower prices.* When bid directly into the wholesale market, demand response—which results in lower demand—can result in lower clearing prices. Demand response *can also lower prices* in the organized wholesale energy markets by reducing the need to dispatch higher-priced generation, or construct new generation, in an effort to satisfy load." (emphasis added)

demand resource planning, program design, and procurement.

The proposed rule also introduces baseline estimation and cost allocation problems, neither of which is addressed in the NOPR and both of which must be fully addressed before any final rules can be issued. The Commission's proposed requirement that those who reduce consumption of electricity from *expected levels* in response to price signals be paid the full LMP for such reductions *in all hours* creates a situation in which baseline estimation becomes a substantial challenge. There is no baseline estimation technique that can accurately and reliably estimate what a customer's energy usage pattern would have been if that customer responds frequently to price signals. With respect to cost allocation, the NOPR and proposed rule do not address how the costs resulting from payments to demand response providers ought to be allocated among market participants. Analysis conducted by ISO-NE found that some cost allocation schemes raise the overall costs charged to end-use consumers more than other schemes. While the payment rate for demand reductions was certainly the most controversial subject in the New England stakeholder process, allocation of these costs was a close second. Any final rule must address cost allocation. If the full-LMP construct is ultimately adopted the payments to demand response providers should be split into components for cost allocation purposes. The first component, the so-called LMP-G component, should be charged to the loadserving entity that is providing the energy; the second component, the excess over the LMP-G (*i.e.*,

the "G" component), should be charged to network load (which is billed to the transmission owners) so that those entities can pass these excess costs through to all customers. Analysis conducted by ISO-NE indicates that splitting the costs between load-serving entities and transmission owners as described above minimizes cost impacts on final customers.

While the proposed rule creates inefficiencies, these inefficiencies can be corrected. These comments provide two alternatives. First, if the objective is payment of the full LMP in all hours in which the consumption of electricity was reduced from expected levels in response to price signals, then the day-ahead purchase of expected energy use, or some other advance purchase requirement, should be required. This is efficient, avoids the need for an estimated baseline, and avoids the need to allocate costs of payments to demand resources. If the Commission does not wish to impose a day-ahead or other advance purchase requirement for expected energy usage, then payment of the LMP net of the retail generation rate (i.e., "LMP-G") is appropriate. Costs of these payments should be borne by the associated load-serving entity whose load was reduced by the demand response. Both the "day-ahead purchase"[6] approach and the

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[6] These comments will use the term "day-ahead purchase" to refer to the purchase of expected energy usage in the day-ahead energy market. However, this term should not be read to exclude other forms of advance purchase requirements. For example, efficient results could also be achieved through an advance purchase established in the retail market through a "demand subscription" service.

LMP-G approach are supported here and in other comments supported by ISO-NE.[7]

The remainder of these comments is structured as follows:

After summarizing the extensive New England stakeholder process addressing the issue of how to best achieve price-responsive demand in the region, ISO-NE's comments explain, first, why economic efficiency (which the states have called the "total resource cost" perspective) is superior to other criteria in ensuring maximum societal benefit from demand resources. The comments demonstrate how the proposed rule could create inefficiencies and increase total resource costs by allowing a demand response provider to benefit by dispatching a demand resource with a marginal cost exceeding the LMP. The comments also describe the day-ahead purchase approach to implementing the NOPR's "full LMP in all hours" payment principle that satisfies the total resource cost perspective. These comments build upon the work conducted by ISO-NE in the review of different approaches to achieve price-responsive demand in New England, as well as the extensive body of knowledge

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[7] *See* Hogan, William, "Demand Response Pricing in Organized Wholesale Markets," May 13, 2010, prepared for the Comments of the ISO/RTO Council in Response to the Federal Energy Regulatory Commission's Notice of Proposed Rulemaking on Demand Response Compensation in Organized Wholesale Energy Markets, Docket No. RM10-17-000, May 13, 2010 (the "Hogan Paper"). *See also* Comments of the ISO-NE Internal Market Monitor being filed today in this proceeding.

developed by the states and by the more recent National Action Plan for Energy Efficiency.

The comments also address an alternative approach to evaluating demand resource cost-effectiveness that has been proposed by some New England stakeholders. In the price-responsive demand stakeholder process initiated by ISO-NE, some stakeholders championed the view that the appropriate test of demand resource cost-effectiveness is the net impact of the demand resource on the rates paid by consumers. These stakeholders stated that a demand resource is cost-effective if the reduction in LMP caused by the dispatch of the demand resource is sufficient to offset the payment to such demand resources. This is not consistent with the principle of economic efficiency and has previously been rejected by most demand resource advocates and states in the development of state-sponsored demand resource programs. The primary test of resource cost-effectiveness should not be based on the distributional effects of resources on different stakeholders—rather, the primary test of resource cost-effectiveness ought to promote the use of the least-cost resources available at each moment in time.

ISO-NE's comments explain that, second, if the Commission does not agree with the day-ahead purchase requirement recommended by ISO-NE to ensure that full LMP is paid efficiently, or if the Commission agrees that the full LMP minus the retail generation rate should be paid for reductions from an estimated baseline, other policy issues will need to be considered by the Commission. These policy issues

have been the subject of much discussion in the New England price-responsive demand stakeholder process and, after the question of what is the appropriate payment rate for demand resources, are the largest demand resource-specific market design issues facing the region. These issues include (1) the measurement and verification of demand reductions (*i.e.*, the customer baseline issue), and (2) the issue of how to allocate among market participants the costs associated with payments to demand response providers. In addition to ensuring that only cost-effective resources are scheduled and dispatched in the energy markets, the market rules filed in response to the final rule must require that the demand reductions produced by demand resources be accurately and reliably measured and verified, and that any resulting costs associated with payments to demand response resources should be allocated to market participants so as to minimize cost impacts on final consumers.

The comments explain why each of these requirements is necessary and the means by which each of these requirements can be met in order to achieve comparable treatment of resources participating in the energy markets. Because different approaches can achieve cost-effective results, the Commission should allow each ISO/RTO to work with its stakeholders to put in place market rules that best fit the circumstances of each region, subject to the requirements mentioned above.

II. BACKGROUND: ISO-NE AND THE NEW ENGLAND STAKEHOLDER PROCESS REGARDING PRICE-RESPONSIVE DEMAND

ISO-NE is the private, non-profit entity that serves as the RTO for New England. ISO-NE operates the New England bulk power system and administers New England's organized wholesale electricity market pursuant to ISO-NE Tariff, which is regulated by the Commission, and operating agreements with transmission owners. In its capacity as an RTO, ISO-NE has the responsibility to plan for and operate the New England bulk power system according to reliability standards established by the Northeast Power Coordinating Council and the North American Electric Reliability Corporation.

ISO-NE has implemented, in consultation with state utility regulators and other stakeholders, a variety of initiatives over the last several years that have been successful in "jump-starting" the demand resource industry. As a result, demand resource capability has grown substantially from the 200 MW that existed at the time ISO-NE implemented the major market restructuring in 2003 that introduced locational marginal pricing and multi-settlement markets (day-ahead and real-time). Figure 1 shows the increase in demand response capacity from the time the Load Response Program was implemented in March 2003 to the present.

Figure 1: ISO-NE Demand Response Resource Enrollment—March 2003 to April 2010.[8]

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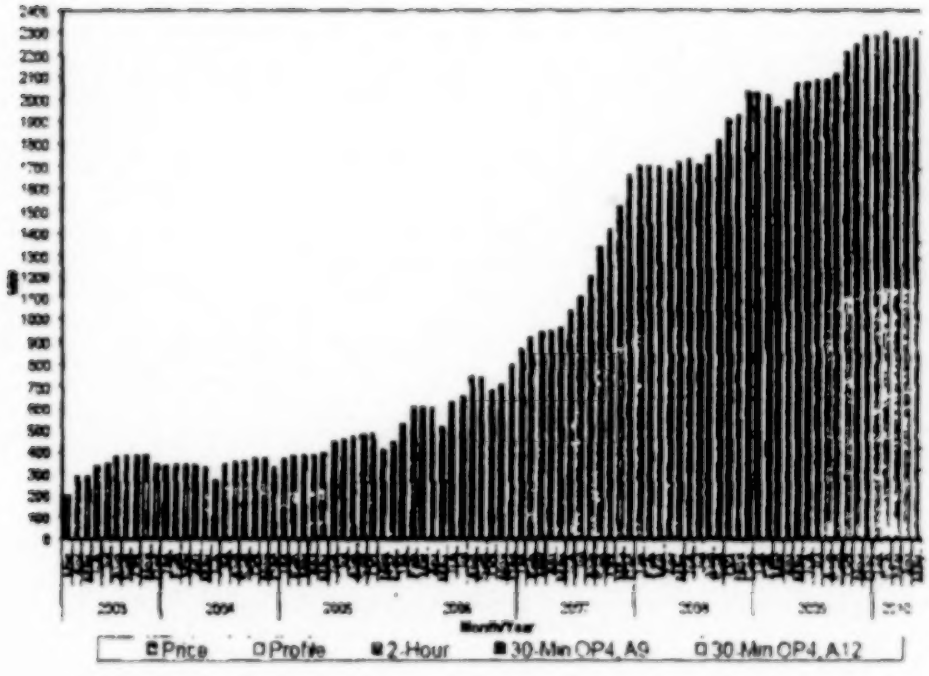
[8] In Figure 1, "Price" refers to the energy-based Real-Time Price Response Program. All other programs indicated in Figure 1 are capacity-based programs. Figure 1 suggests that the enrollment of demand response resources in wholesale markets responds well to capacity price signals, but not to energy price signals. Similar to peakers, low-capacity factor demand response resources receive most of their value from capacity markets and not from energy markets because demand response resources are dispatched infrequently. Figure 1 shows that the escalation of demand response resource enrollment is coincident with the escalation of capacity prices—for example, demand response enrollment escalated substantially at the end of 2006/beginning of 2007 coincident with the start of the ICAP Transitional Period, the predecessor to the Forward Capacity Market, in which capacity prices of $3.05/kW-month increasing to $4.10/kW-month were paid to capacity resources including capacity-based demand response resources. Prior to this time, capacity prices were near zero. Meanwhile, participation in energy-based programs such as the Real-Time Price Response Programs steadily declined even though the program has not changed since its implementation in 2003. Today, less than 70 MW participate in the Real-Time Price Response Program. Many Real-Time Price Response Program participants switched their enrollment to programs receiving capacity payments as capacity prices escalated, suggesting that demand response participation in wholesale markets will be affected more by the design of capacity markets than energy markets.



Key drivers to the growth of demand resources in New England include:

- Establishing a Demand Resources Department in 2002;
- Opening energy markets that establish day-ahead and real-time Locational Marginal Prices ("LMPs") in 2003, which enabled load-serving entities to purchase energy on a price-sensitive basis;
- Implementing the existing Load Response Program, which is a broad menu of demand response programs addressing system reliability and price responsiveness, in 2003;

- Issuing a gap Request For Proposals to maintain reliability in Southwestern Connecticut from 2004 through 2008, through which ISO-NE administered contracts involving 260 MW of demand resources;
- Establishing a winter supplemental demand-response program in reaction to the potential loss of natural gas supplies that may have resulted from the devastation of Hurricanes Katrina and Rita;
- Implementing a Demand Response Reserves Pilot Program in 2006 to determine how small demand response resources (less than 5 MW) can provide a functionally equivalent reserve product;
- Commencing transition payments related to the Forward Capacity Market ("FCM") in 2006 for which demand response program participants, energy efficiency resources, and distributed generation resources were eligible; and
- Executing the first three Forward Capacity Auctions in which demand resources successfully competed with traditional generation resources. As a result, demand resources will provide up to approximately 2,900 MW of capacity annually to the New England region.

While much has been done to expand the region's demand resource capability, ISO-NE, NEPOOL and NECPUC believe that more can and should be done. In October 2008, ISO-NE initiated a stakeholder pro-

cess to develop new approaches to achieve price-responsive demand ("PRD") in New England. The stakeholder process complied with the requirements of Section III.E.1.3 of the ISO New England Inc. Transmission, Markets and Services Tariff (the "ISO-NE Tariff")[9] and the Commission's 2008 order regarding ISO-NE's Day-Ahead Load Response Program ("DALRP").[10] That order required, *inter alia*, a review of the customer baseline methodology used in the DALRP

To encourage greater price responsiveness of demand resources in the region, ISO-NE had previously developed and implemented, in consultation with stakeholders, a Real-Time Price Response Program ("RTPRP") and the DALRP. Both programs were set to expire on May 31, 2010, coincident with the first Capacity Commitment Period of the Forward Capacity Market. Section III.E.1.3 required undertaking a stakeholder process to consider whether to allow the RTPRP and the DALRP to expire, continue the programs in their current form, or implement modified programs or other market designs.

To facilitate full consideration of the options for PRD, ISO-NE and NEPOOL made a filing, accepted by the Commission in October 2009,[11] extending the

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[9] Capitalized terms not otherwise defined herein have the meanings ascribed thereto in the ISO-NE Tariff.

[10] *ISO New England Inc.*, 123 FERC ¶ 61,266 (2008) (the "DALRP Order").

[11] *See* delegated letter order issued in Docket No. ER09-1737-000 (October 29, 2009).

expiration date of the RTPRP and the DALRP from May 31, 2010 to May 31, 2012 and modifying the DALRP eligibility requirements to allow Real-Time Demand Response Assets (a type of Demand Resource participating in the Forward Capacity Market) to participate in the DALRP starting June 1, 2010.[12]

During the period between October 2008 and March 2010, the region's stakeholders and state regulators met over 24 times to develop new approaches for achieving PRD in the New England region. These efforts were reported to the Commission in a series of filings dated March 27, 2009, July 31, 2009, and December 18, 2009.[13] As explained in the December 18, 2009 report of ISO-NE and NEPOOL regarding the PRD stakeholder process, the process produced a design basis document ("DBD"), which:

> outlined two options available for market participants with demand resources to participate in the region's wholesale energy market, a "Supply-Side Option" and a "Demand-Side Option." As described in the PRD DBD, under the Demand-Side Option, Market Participants could purchase a voluntary wholesale product in which the energy component is priced on an hourly, real-time basis. Under the Supply-Side Option, Market Participants could of-

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[12] The first Capacity Commitment Period of the Forward Capacity Market commences on June 1, 2010.

[13] *See* Report of ISO New England Inc. and New England Power Pool Regarding Treatment of Price-Responsive Demand in the New England Electricity Markets, Docket No. ER08-830-000, filed March 27, 2009, July 31, 2009, and December 18, 2009.

fer load reductions into the wholesale energy markets in a manner similar to supply offers of generation resources, which would be integrated into the market-clearing, price-setting, and resource-scheduling algorithm. In stakeholder deliberations, the major area of disagreement regarding the Demand-Side Option concerned the pricing of capacity in the voluntary wholesale product. Some of the major areas of disagreement regarding the Supply-Side Option concerned the payment levels for demand resources, the thresholds for participation, and allocation of costs resulting from payments to suppliers of demand resources.[14]

In response to the December 18, 2009 filing, the Consumer Demand Response Initiative ("CDRI") submitted a request to the Commission for policy guidance with respect to the Supply-Side Option being discussed in the New England stakeholder process. In ISO-NE's answer to the CDRI request, ISO-NE informed the Commission of its plan to prepare an initial set of market rules for PRD (the "Phase 1" rules), vet them through the stakeholder process, and file them with the Commission under Section 205 of the Federal Power Act on or before April 30, 2010.[15] Further, ISO-NE planned to file a second set of rules (the

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[14] *See* Report of ISO New England Inc. and New England Power Pool Regarding Treatment of Price-Responsive Demand in the New England Electricity Markets, Docket No. ER08-830-000 (filed December 18, 2009).

[15] *See* filing of ISO-NE and NEPOOL in Docket No. ER08-830-000, at 6 (February 12, 2010).

"Phase 2" rules) reflecting the Commission's rulings on the Phase 1 rules. The Phase 2 rules would have built upon the Phase 1 rules and would have completed the set of market rules needed to enable demand response resources to participate directly in the supply-side of the New England energy markets.[16] The Phase 1 rules would have addressed product definition, eligibility, payment rate and cost allocation. The Phase 2 rules would have addressed demand reduction offer parameters, real-time scheduling and dispatch of demand resources, asset enrollment requirements, measurement and verification of demand reductions, rights and obligations of demand resources, and internal market monitoring review of demand reduction offers.

The NEPOOL Markets Committee was preparing to vote on ISO-NE's proposed Phase 1 rules at its March 23, 2010 meeting. Just prior to that meeting, however, the Commission initiated the NOPR on Demand Response Compensation in Organized Wholesale Energy Markets. The NOPR addresses some of the key issues that the Phase 1 rules would have addressed, particularly the payment rate and participation threshold issue. Because the Commission will be addressing these key issues generically in the NOPR proceeding, ISO-NE withdrew its request for a stakeholder vote on the proposed Phase 1 market rule language.

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[16] *Id.*, at 6-7.

As this background indicates, ISO-NE's comments in this proceeding have been informed by almost 19 months of analysis and discussions with the region's stakeholders and state regulators on issues concerning the participation of demand resources in the energy markets.

III. APPROACHES TO ENSURING COST-EFFECTIVENESS OF DEMAND RESOURCES IN THE ENERGY MARKETS

A. The ISO-NE Energy Market is Designed to Achieve Economic Efficiency by Minimizing Total Resource Costs

The wholesale energy market administered by ISO-NE is designed to achieve economically-efficient outcomes by dispatching the least expensive resources available to meet the demand for energy, subject to reliability constraints.[17] To achieve this, resources are scheduled in the order of the lowest to highest cost of supply—*i.e.*, those with the lowest operating costs should be scheduled first, with increasingly higher cost resources being scheduled next to meet increasing levels of consumption. To determine generator operating costs for the purposes of scheduling, generators submit supply offers to ISO-NE—*i.e.*, the price at which the generator is willing to supply an amount of energy to the wholesale energy market. Competition among generators drives the price of these supply of-

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[17] *See* Market Rule 1, Section III.1.7.6 (a). Market Rule 1 is Section III of the ISO-NE Tariff.

fers to reflect each generator's marginal cost of production.[18]

To achieve comparability between generators and demand resources participating in the energy markets, supply offers submitted by demand resources into the wholesale energy market must also reflect the marginal cost of each resource. In this way, the costs of all resources (generators and demand resources) can be compared and scheduled such that economic efficiency is maintained—that is, the lowest cost resources are used first and most frequently. If a demand resource has a lower marginal cost than a generator, that demand resource should be scheduled first and more frequently than that generator. While the marginal cost of a generator is driven primarily by fuel and variable operating and maintenance costs, the marginal

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[18] In a competitive market design in which the market-clearing price is set by the last accepted supply offer used to meet consumption, suppliers have a strong incentive to submit supply offers equaling their true marginal operating costs. Because only those generators that are scheduled and dispatched earn energy revenues, generators submitting supply offers that exceed their marginal operating costs—in an attempt perhaps to increase profit by inflating prices above costs—run the risk of being out-competed by other generators that submit lower-priced offers. Generators submitting above-cost supply offers in a competitive market, therefore, reduce their opportunity to earn revenue. On the other hand, a generator that submits a supply offer that is less than its marginal operating cost—in an attempt perhaps to out-compete other generators and be dispatched more frequently to increase its chances of earning greater revenues—runs the risk of being scheduled and dispatched when the market-clearing price is less than its operating costs, which would erode its profits.

cost of a demand resource is driven by the marginal opportunity cost of consumption, which could be driven by one or more factors such as:

- The marginal cost of a distributed generator operated by the consumer (*i.e.*, the fuel and variable operating and maintenance costs of the distributed generator);
- The marginal cost of a substitute form of energy (e.g., gas-fired steam chillers instead of electricity for air conditioning);
- The marginal cost of implementing an energy efficiency, load control, or load shifting strategy, or
- The marginal value that the consumer places on electricity consumption that is foregone when the consumer interrupts its end-use energy consumption.

B. Economic Efficiency is the Basis by Which States Evaluate Demand Resource Planning, Program Design, and Procurement

The use of economic efficiency as the basis for demand resource program design is consistent with the resource cost-effectiveness principles that have been developed by state regulatory bodies over the past three decades to guide demand resource planning, program design and procurement. Consumer advocates have similarly emphasized that, when a demand resource is "fairly projected to be *the least cost resource*,

it should be the preferred resource in a prudent resource planning and acquisition practice."[19] The New England states have been leaders in the development of regulatory policies guiding the development of demand resources and the design of demand resource programs based on the principle of cost-effectiveness. Today, some New England states are committed to capturing *all cost-effective* demand resources within fairly aggressive timeframes.[20] Also, the recent National Action Plan for Energy Efficiency—developed by a group of over 60 gas and electric utilities, state agencies, energy consumers, energy service providers, and environmental/energy efficiency organizations under the auspices of the U.S. Department of Energy and the U.S. Environmental Protection Agency—has as its primary goal the achievement of "*all cost-effective* energy efficiency by 2025."[21] The approach utilized in the development of the National Action Plan

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[19] *See* The National Association of State Utility Consumer Advocates Principles for Energy Efficiency Programs, Resolution 2009- 02, *available at* http://www.nasuca.org/archive/res/index.resoltuions.php (emphasis added).

[20] For example, *see* "2010-2012 Massachusetts Joint Statewide Three-Year Electric Energy Efficiency Plan," October 29, 2009, *available at* http://www.ma-eeac.org/docs/DPU-filing/ElectricPlanFinalOct09.pdf. Page 11 notes that " . . . this Plan seeks to capture *all available cost-effective energy efficiency* for the three-year period beginning January 1, 2010 with the consideration of factors and concerns noted at the Council, including, but not limited to, bill impacts, environmental benefits, and the need for a reasonable ramp-up schedule" (emphasis added).

[21] *See* http://www.epa.gov/cleanenergy/energy-programs/napee/index.html. ISO-NE was a member of the leadership group.

for Energy Efficiency is being considered by the Commission for the development of the National Action Plan on Demand Response.[22]

Tests used by demand resource program administrators to evaluate the cost-effectiveness of demand resources in the electricity industry are based on the fundamental principle that a demand resource is cost effective when its cost is less than the cost of producing an equivalent amount of energy. That is, a demand resource participating in the energy market is cost-effective when its marginal cost is less than the "***avoided cost of energy***." For example, the total resource cost test ("TRC"), the most commonly used primary metric of demand resource cost-effectiveness among the states, is based on this fundamental principle.[23] In a competitive energy market such as the one administered by ISO-NE, the avoided cost of energy equals the LMP.

The TRC perspective is consistent with the economic efficiency principles supported by ISO-NE for

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[22] *See* National Action Plan on Demand Response, Federal Energy Regulatory Commission Staff, Docket No. AD09-10, March 11, 2010, at pp. 21, 23, and 81-82.

[23] *See* the paper developed for the National Action Plan for Energy Efficiency: *Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers*, Energy and Environmental Economics, Inc. and Regulatory Assistance Project at pp. ES-2 and 5-1 (2008), *available at* http://www.epa.gov/cleanenergy/documents/cost-effectiveness.pdf ("National Action Plan for Energy Efficiency").

the design of the energy market in general, and for the integration of demand resources into the energy market in particular. In New England, Maine, Massachusetts, New Hampshire and Vermont use the TRC or the societal cost test[24] as the primary test of demand resource cost-effectiveness.[25] Connecticut uses the TRC as a secondary consideration,[26] though more recent information suggests that Connecticut is now using the societal cost variant of the TRC approach as its primary test of demand resource cost-effectiveness.[27] Rhode Island's primary cost-effectiveness test is not specified.[28]

C. The Proposed Rule Will Produce Economic Inefficiencies in the Energy Markets

Because a demand resource simultaneously affects both supply and demand, a demand response provider working with a consumer can receive both a payment

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[24] The societal cost test ("SCT"), or simply the "societal test," is a variant of the TRC that includes consideration of non-energy benefits and costs that are not priced in the market such as environmental externalities.

[25] National Action Plan for Energy Efficiency, at p. 5-1.

[26] In Connecticut, demand resource cost-effectiveness is based primarily on the program administrator cost test ("PACT"), which examines the costs and benefits of a demand resource program from the perspective of the entity implementing the program (*e.g.*, utility, government agency, nonprofit, or other third party). National Action Plan for Energy Efficiency, at pp. 5-1, 5-2 and 6-2.

[27] *See* Integrated Resource Plan for Connecticut, January 1, 2010. Prepared by: The Brattle Group, Connecticut Light and Power, and United Illuminating Company.

[28] National Action Plan for Energy Efficiency, at p. 5-1.

for reducing demand and accrue savings in its energy bill for the same reduced energy consumption. If the market design does not take into account the combined impact of both incentives in its construction, a demand response provider might earn full-LMP payments for demand reductions while the customer simultaneously accrues energy bill savings for the same demand reductions. The total financial benefit in this case from dispatching a demand resource exceeds the LMP This makes it profitable to dispatch a resource with a marginal cost exceeding the LMP, which is inefficient and raises total resource costs. Recognizing that both incentive payments and bill savings are relevant to the decision of a demand response provider to reduce consumption is essential to achieving an efficient market design.

Demand response providers would consider the sum of incentive payments from the market administrator and savings in the consumer's energy bill resulting from reductions in energy consumption. The demand response provider would compare this "double benefit" to the marginal cost of its demand resource in its decision to dispatch its demand resource capability; the demand response provider would dispatch its demand resource capability if total benefits exceed the costs. The double benefit produced by a full-LMP payment approach gives demand response providers the incentive to dispatch a demand resource whose marginal cost exceeds the LMP In a report shared with the region's stakeholders and state utility regulators in February 2009, ISO-NE found that approaches that pay full LMP without requiring the advance

purchase of power could result in high-cost demand resources displacing low-cost resource available in the wholesale market:

> The combination of bill savings and payments received by [demand response] program participants gives them the incentive to defer consumption whose value may exceed the LMP, and/or to switch to alternative energy sources that cost more than the LMP. Such a program design, therefore, results in an inefficient market outcome that inefficiently utilizes society's resources. For example, if the retail rate is $80/MWh and the LMP is $90/MWh, a customer who is paid the LMP to reduce consumption would be able to earn an additional $20/MWh by using a $150/MWh on-site generator ($80 bill savings plus $90 payments $150 generator = $20 net gain) to reduce its net metered load. Thus, the program incentive payment results in an inefficient utilization of society's resources by encouraging the use of a more expensive $150/MWh resource even though a less expensive $90/MWh resource in the wholesale market was available to serve the customer's load. This example applies whether an on-site generator is used or consumption valued at the same $150/MWh is foregone.[29]

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[29] *See* http://www.isone.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2009/feb202009/a2_iso_status_report_prd_draft_versi on_1_02_13_09.pdf, p. 8. On the other hand, if the customer first purchased its expected energy requirements at, say, the $80/MWh retail rate, the customer's decision to dispatch its demand

In contrast to demand resources, wholesale generators dispatched in the energy market receive only the LMP since they do not accrue bill savings. Under a policy of full-LMP payment for both generated energy and demand reductions, generators receive the *single* benefit of the full-LMP payment whereas demand response providers receive the *double* benefit of the full-LMP payment and bill savings. In this sense, demand resources and wholesale generators are fundamentally different, warranting different treatment in the energy markets to achieve comparable and symmetric incentives that minimize total resource costs. Failing to recognize the fundamental difference between a wholesale generator and a demand resource in the design of incentive payments for demand response would result in the inefficient utilization of society's resources under a full-LMP payment approach—*i.e.*, higher-cost demand resources would displace lower-cost generation resources available at that time. Such a result violates the fundamental principle that a demand resource is cost-effective only when its cost is less than the avoided cost of energy (*i.e.*, the LMP).

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resource would be based on a comparison between the full LMP and the marginal cost of its demand resource—*i.e.*, the customer would compare the cost of its demand resource to the LMP in a manner comparable to all other resources participating in the energy market. Under these circumstances, the customer would not dispatch its demand resource, which is the efficient solution in this case, since its cost at $150/MWh would be higher than the LMP at $90/MWh.

D. Example of Efficient and Inefficient Market Designs and Outcomes with Payment of the Full LMP

The following examples illustrate how economically -efficient wholesale market rules can be designed—which is consistent with the TRC perspective—to support the fundamental principle that the least expensive resources (whether generation or demand response) should be scheduled in the wholesale energy market. These cases show that:

- Payments for load reductions from demand resources are justified to drive down total resource costs when the marginal cost of a demand resource is less than the LMP. Conversely, payments for load reductions from demand resources are not justified when the marginal cost of a demand resource exceeds the LMP because such payments would raise total resource costs;
- The primary motivation of a wholesale generator is to earn revenue in excess of costs, while the primary motivation of a participant with a demand resource is to reduce its net energy bill.
- If a participant with a demand resource is not required to purchase its expected energy requirements at, for example, the day-ahead LMP, but is paid the full LMP for reductions in expected energy use, the participant is presented with the opportunity to reduce its net energy bill by dispatching a high-cost demand

resource and displacing lower-cost resources available on the grid. That is, the private incentive presented to the participant rewards behavior that is not consistent with an efficient market outcome.

- To achieve comparable treatment of all resources (generation and demand resources) in the energy markets in which all resources are dispatched in economic-merit order, participants with demand resources must purchase their consumer's expected energy consumption at, for example, the day-ahead LMP.

The following examples assume that a 10 MW consumer decides to participate in the wholesale energy market by utilizing its demand resource capability.[30] This market participant determines that it is not worth buying energy if the cost of that energy exceeds $200/ MWh. This $200/MWh figure could be the result of an evaluation of the marginal opportunity cost of the energy, which could be based on the foregone value of energy consumption, the cost of a substitute form of energy, the marginal cost of implementing an energy efficiency measure, a load control device or a load shifting/management strategy, or the marginal cost of distributed generation with a dispatch cost (*i.e.*, a fuel and variable operations and maintenance cost) of $200/ MWh.[31]

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[30] This consumer could participate in the wholesale market either directly or through an aggregator. The examples that follow do not depend on how the consumer participates in the wholesale market.

[31] While marginal costs may be difficult to estimate and may shift over time, it is difficult to imagine a business consumer willing to

Further assume that the participant is able to purchase energy (either directly or through a retail customer aggregator) from the day-ahead energy market at the day-ahead LMP, which is $100/MWh in these examples.

Table 1 shows how this participant would behave depending on how incentive payments for PRD are designed. The examples include: no incentive payment (Base Case), incentive payment with day-ahead purchase (Case 1), incentive payment with day-ahead purchase and a lower real-time LMP (Case 2), and incentive payment with no day-ahead purchase (Case 3). In all cases other than the Base Case, the incentive payment is the full real-time LMP. For simplicity, Table 1 illustrates only a single hour, though these results could be generalized across numerous hours.

Table 1: Impact of Demand Response Incentives on Price-Responsive Behavior and Total Resource Costs

Scenario	Was DR dispatched?	Day-Ahead LMP ($/MWh)	Real-Time LMP ($/MWh)	DR Marginal Cost ($/MWh)	Real-Time Energy Use (MWh)	Day-Ahead Energy Bill ($)	Cost of Dispatching DR ($)	DR Payment @ Full RT LMP ($)	Net Energy Bill ($)	Total Resource Cost ($)
Base Case	No	$100	$300	$200	10	$1,000	$0	$0	$1,000	$3,000
Case 1	Yes	$100	$300	$200	0	$1,000	$2,000	$3,000	$0	$2,000
Case 2	No	$100	$150	$200	10	$1,000	$0	$0	$1,000	$1,500
Case 3	Yes	$100	$150	$200	0	$0	$2,000	$1,500	$500	$2,000

so a successful consumer would stop buying such a high-priced input and seek lower-priced alternatives. With respect to electricity, a successful consumer (or an agent working on behalf of the consumer) would specify in the day-ahead energy market the most it would be willing to pay for energy based on the marginal cost of the demand resource under the consumer's control, which also happens to equal the consumer's marginal opportunity cost of energy. In this way, the consumer remains in control of its production costs and ultimately its profits.

a) Base Case—No Incentive Payment is Inefficient

The Base Case—*i.e.*, the first line of Table 1—assumes no incentive payments for price-responsive demand and a real-time LMP of $300/MWh. Given the lack of incentive payments for dispatching its demand resource, the market participant is more than willing to purchase all of its expected energy requirements from the day-ahead energy market, which cleared at a $100/MWh, than to dispatch its demand resource at a cost of $200/MWh.[32] Accordingly, the participant places 10 MWh of load on the grid and is billed $1,000 *(i.e.*, 10 MWh times the day-ahead price of $100/MWh)—note that in the absence of any offsetting incentive payments (at the full real-time LMP or otherwise) the participant's energy bill would have been $2,000 if it dispatched its demand resource at a cost of $200/MWh (*i.e.*, 10 MWh times $200/MWh demand resource marginal cost). Because the participant does not dispatch its demand resource, there are no demand resource costs (and, of course, no incentive payments). The participant's net energy bill is $1,000.

However, Table 1 also shows that the total resource cost associated with the participant consuming 10 MWh in this hour is $3,000. This is because the real-

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[32] According to this example, the participant would submit a Demand Bid into the Day-Ahead Market to purchase 10 MWh of energy at a price not to exceed $200/MWh. The fact that the day-ahead LMP clears at a price far lower than its Demand Bid accrues to the benefit of the customer.

time LMP, which represents the actual marginal or avoidable cost of generation, was $300/MWh. Meanwhile, a less expensive resource was available—*i.e.*, the participant's $200/MWh demand resource. The $200/MWh demand resource could have been used instead of the $300/MWh resource on the grid. Had the lower cost demand resource been used, total resource costs would have been $2,000 instead of $3,000. Therefore, the Base Case shows that not using the demand resource under these circumstances violates the fundamental cost-effectiveness principle—*i.e.*, if it is less expensive to save energy than to produce it, society benefits from saving the energy. However, with no incentive payments, the participant will consume high-cost energy from the grid even though the cost of saving energy is less than the avoided cost of energy. The Base Case indicates that the energy market should make payments to participants with demand resources so as to provide incentives for the utilization of cost-effective resources.

b) Case 1—Incentive Payment with Day-Ahead Purchase is Efficient

In contrast to the Base Case, Case 1 gives the market participant the opportunity to receive the full real-time LMP for dispatching its demand resource. With this incentive payment, the net energy bill paid by the participant is significantly lower when the participant dispatches its demand resource. As in the Base Case,

the participant purchases its expected energy requirements at the day-ahead LMP at a cost of $1,000. By dispatching its demand resource, the participant incurs a cost of $2,000; however, the participant also receives the full real-time LMP for reducing its demand in real time. By receiving the full real-time LMP for its reduced demand, the participant receives $3,000 of incentive payments. Therefore, the participant reduces its net energy bill to $0, which is far less than the $1,000 energy bill it would have paid as shown in the Base Case if it did not dispatch its demand resource.

Most importantly, total resource costs are lower in Case 1 than in the Base Case—total resource costs are $2,000 in Case 1, which is $1,000 lower than in the Base Case. This is because the marginal cost of the demand resource at $200/MWh is less expensive than the $300/MWh cost of the marginal resource setting price in the wholesale energy market. That is, using the demand resource under these circumstances is consistent with the TRC perspective and is cost-effective —the marginal cost of the demand resource is less than the marginal cost of the resource setting price in the wholesale energy market. Therefore, the provision of the full LMP incentive payment induces the participant to dispatch a cost-effective resource, resulting in a reduction in total resource costs.

c) Case 2—Incentive Payment with Day-Ahead Purchase Leads to Efficient Dispatch

Case 2 shows what happens when the real-time LMP changes to $150/MWh, all other things remaining

the same as in Case 1. As in Case 1, the participant purchases its expected energy requirements at the day-ahead LMP, which clears at $100/MWh. Further, the participant is offered to be paid the full real-time LMP for any energy it does not consume in real time. However, since the real-time LMP is $150/MWh, it chooses not to dispatch its demand resource. By not dispatching its demand resource, Case 2 shows that the participant's net energy bill for the hour is $1,000. Had the participant dispatched its demand response resource, the participant would have raised its net energy bill to $1,500. That is, the participant would have paid $1,000 for its cleared Day-Ahead Demand Bid, would have incurred a cost of $2,000 for dispatching its demand resource, and would have received an incentive payment of only $1,500 resulting in a net energy bill of $1,500 (*i.e.*, $1,000 + $2,000 - $1,500 = $1,500). Presumably, participants would not voluntarily raise their net energy bills, so they would not dispatch a $200/MWh demand resource in this instance. However, not dispatching the demand resource in this instance is the right solution from a TRC perspective. The cost of dispatching the resource was $200/MWh, but the cost of the marginal resource on the system was $150/MWh—*i.e.*, the marginal cost of the demand resource exceeds the avoided cost of energy, so it is not cost-effective to dispatch the demand resource in this instance.

Some stakeholders may argue that a participant should be able to offer demand reductions into the wholesale energy market as a supply resource without needing to purchase its expected energy requirements

from the day-ahead energy market or from an aggregator securing energy from the wholesale energy market on its behalf. That approach, however, would not comply with the TRC perspective, as demonstrated in the discussion of Case 3, below.

d) Case 3—Incentive Payment without Day-Ahead Purchase is Inefficient

Case 3 shows what would happen if a market participant in a price-responsive demand program were not required to purchase its expected energy requirements in the day-ahead energy market (or from an aggregator purchasing energy from the wholesale energy market on behalf of the participant). By not requiring the participant to purchase its expected energy requirements from the day-ahead energy market, its day-ahead energy bill is $0. Additionally, by dispatching its demand resource and demonstrating a demand reduction of 10 MWh, the participant receives a payment at the full real-time LMP equaling $1,500. However, the participant incurs a cost of $200/MWh for dispatching its demand resource for a total cost of $2,000. Under this approach, Case 3 shows that the participant's net energy bill (i.e., the difference between the $2,000 cost for dispatching its demand resource and the $1,500 incentive payment) is $500.

For obvious reasons, a wholesale generator would refrain from submitting a supply offer that would obligate it to produce energy at a cost exceeding its revenue. While Case 3 shows that the cost of dispatching the demand resource is greater than the incentive payment, it would be incorrect to assume

that the participant with a demand resource would behave like a wholesale generator—while generators do not have the incentive to dispatch resources whose cost exceeds the LMP, *participants with demand resources that are not required to purchase their expected energy requirements will have an incentive to dispatch a demand resource whose cost exceeds the LMP.* Note that the customer's net energy bill in Case 3 is half that of Case 2 with the same day-ahead and real-time prices. Whereas the primary motivation of a wholesale generator is to earn revenue that exceeds its cost, *the primary motivation of a participant with a demand resource is to reduce its net energy bill.* Therefore, if a participant with a demand resource is not required to purchase its expected energy requirements, the participant is presented with the opportunity to reduce its net energy bill by dispatching a high-cost demand resource and displacing lower-cost resources available on the grid.[33]

The approach illustrated in Case 3, therefore, disrupts the comparable treatment of resources in the energy markets. While wholesale energy markets schedule the dispatch of generation resources in economic-merit order—*i.e.*, in the order of increasing resource marginal costs—paying full LMP without re-

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[33] In fact, the participant would have the incentive to dispatch a demand resource that costs up to $250/MWh (even though the real-time LMP is only $150/MWh) all other things equal. The participant would have the incentive to dispatch a demand resource as long as the difference between the cost of the demand resource and the real-time LMP did not exceed the day-ahead LMP.

quiring a participant with a demand resource to purchase its expected energy requirements could very well result in a high-cost demand resource being dispatched before a lower-cost generation resource.[34] Further, and most importantly, Case 3 shows that dispatching the demand resource increases total resource costs from $1,500 to $2,000. Therefore, not requiring the participant to purchase its expected energy requirements gives the participant the incentive to dispatch demand resources that are not cost-effective relative to the marginal resource available on the grid, resulting in higher total resource costs. That is, when a participant is not required to purchase its expected energy requirements but is paid the full LMP for reductions in expected energy use, the private incentive presented to the participant rewards behavior that is not consistent with an efficient market outcome.

To avoid this perverse outcome, participants must purchase their expected energy consumption at the day-ahead LMP or from a retail customer aggregator purchasing energy from the wholesale energy market on behalf of the participant. By requiring that a participant purchase its expected energy consumption, participants would improve their financial position only by dispatching a demand resource that is cost effective. Conversely, not requiring participants to

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[34] If the real-time LMP is lower than the day-ahead LMP, the participant would certainly not be encouraged to dispatch its demand resource in real time, but may instead decide to take advantage of the low real-time price and consume more energy at the lower price, which increases the consumer's value.

purchase their expected energy consumption gives participants the incentive to take actions that increase total resource costs, which violates the fundamental test of demand resource cost-effectiveness.

E. Basing Resource Cost-Effectiveness on LMP Reduction is Inconsistent with Economic Efficiency Principles, and is Inconsistent with the Views of Most States on What Constitutes a Proper Economic Analysis

Some stakeholders may argue that the appropriate test of demand resource cost-effectiveness should be based on the net impact of the demand resource on the rates paid by consumers. During the price-responsive demand stakeholder process initiated by ISO-NE in October 2008, some stakeholders put forth the view that a demand resource was cost-effective if and only if the reduction in LMPs caused by the demand resource was sufficient to offset the payments to demand response providers. This should not be the basis for demand resource compensation because it is inconsistent with the principle of economic efficiency.

This perspective, where cost-effectiveness of demand-side actions is based on the net financial impact of such actions on all other consumers, was first defined in February 1983 with the publication of the "Standard Practice for Cost-Benefit Analysis of Conservation and Load Management Programs."[35] This

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[35] *See* California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects, July 2002, at p. 1, *available at* http://drrc.lbl.gov/pubs/CA-SPManual-7-02.pdf.

perspective is known to the demand-side management community as the "ratepayer impact measure" or "RIM" test, which is also known to practitioners as the "non-participant" or "no-losers" test. Under the RIM perspective, cost-effectiveness is judged on whether the demand resource raises or lowers electricity rates to consumers—that is, a demand resource is cost-effective if it lowers electricity rates and is not cost-effective if it raises rates. In a competitive wholesale market setting, a RIM approach might examine the impact of the demand resource on LMPs relative to the payments made to demand response providers—if the reduction in LMPs offset the payments to demand response providers, this should translate eventually to lower retail electricity rates to all consumers, at least in the short-run. If the reduction in LMPs is sufficient to offset the additional cost of demand resources charged to consumers—particularly to those consumers that do not implement demand resources (*i.e.*, the non-participants)—then the demand resource is considered to be cost-effective.

While the RIM perspective has obvious appeal to consumers of energy, many demand resource advocates and states have rejected the RIM test as a primary test of demand resource cost-effectiveness.[36] The only jurisdiction that reportedly uses the RIM perspective as the primary test of demand resource cost effectiveness is Florida.[37] In New England, only New Hampshire considers the RIM perspective in its

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[36] National Action Plan for Energy Efficiency, at pp. 5-1, 5-2.

[37] *Id.* at p. 5-1.

review of proposed demand resource programs, though it uses the TRC perspective as its primary consideration.[38] The primary test of resource cost-effectiveness should not be based on the distributional effects of resources on different stakeholders[39]—rather, the primary test of resource cost-effectiveness ought to promote the use of the least-cost resources available at each moment in time. Moreover, a RIM perspective is not consistent with the treatment of other resources participating in the energy markets. For example, generation is not dispatched and paid for only when the generation reduces LMPs—generation is dispatched and paid for when it is cost-effective.

F. RIM Has Unintended Consequences and is Likely to be Counterproductive in the Long-Run

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[38] *Id.* at p. 5-2.

[39] While the TRC or the SCT is used as the primary test of demand resource cost-effectiveness in most states, some states use the RIM perspective to modify demand response program design to address bill impacts on nonparticipants. For example, see the recent recommendations of the Integrated Resource Plan for Connecticut, January 1, 2010. While an "All Achievable Cost-Effective" demand resource strategy utilizing a societal cost approach was identified, the plan recommended a more moderate demand resource expansion strategy to address rate impacts on non-participants. The plan found that capturing all cost-effective demand resources would raise the overall rates of non-participants whereas a more moderate and targeted demand resource strategy would reduce generation service charges offsetting the increase in charges to acquire the cost-effective demand resources. *Id.*, pp. I-5 – I-6.

In the current debate, however, some of the stakeholders will advocate a return to the RIM perspective as a measure of cost-effectiveness for demand resources, particularly for demand response resources. The RIM perspective favors low-capacity factor demand response resources[40] that dispatch their demand reduction capability for a few high-priced hours during a season or year. These demand response resources have a relatively low impact on overall energy consumption compared to energy efficiency and base-load distributed generation demand resources. However, the RIM perspective tends to be unfavorable to higher capacity factor resources, such as energy efficiency, that may be more cost-effective from a total resource cost perspective.

Additionally, the Commission's proposed policy that the full LMP be paid in all hours creates a situation in which demand resources may interrupt demand at times when LMPs are low and the supply curve is relatively flat. A reduction in demand during such hours has little or no impact on LMPs. A RIM perspective, therefore, would find that demand reductions during such hours are not cost-effective. Accordingly, the RIM perspective does not support payment of full LMP in all hours. ISO-NE's recommendation that cost-effectiveness judged by a TRC perspective

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[40] A resource with a low-capacity factor is one that produces little output for its size. The capacity factor of a demand resource is defined as: (MWh of demand reduction produced by the demand resource during the season or year) ÷ (MW demand reduction capacity of the demand resource x hours in the season or year).

would not limit the dispatch of demand resources to high- priced hours. Rather, dispatch would occur whenever a resource is cost-effective (*i.e.*, when the marginal cost of the resource is less than the LMP).

In addition to encouraging the dispatch of resources that are not cost-effective, endorsing the RIM perspective because of its focus on reducing LMPs could have numerous unintended consequences such as:

- **LMP reductions are likely to be transient at best.** If the financial returns of suppliers (generation and demand resources) are depressed by suppressing LMPs below market clearing levels in the short-run, existing supply would be encouraged to exit the market and/or new supply would be discouraged from entering the market.[41] As supply becomes more constrained, LMPs would rise. Analysis by ISO-NE demonstrated that, ultimately, any consumer gains from suppression of LMPs in the short-run will result in higher prices and costs in the long-run as investors adjust their resource portfolios over time in response to prices.[42]

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[41] See Allcott, Hunt (2009). "The Smart Grid, Entry, and Imperfect Competition in Electricity Markets." MIT Department of Economics and MIT Energy Initiative; NYU Department of Economics.

[42] *See* http://www.is-one.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2009/feb202009/a2_iso_status_report_prd_draft_version_1_0 2_13_09.pdf, at pp. 40-43.

- **LMP reductions result in higher capacity payments during Shortage Events.** The interaction between the Forward Capacity Market and the energy market in New England tends to neutralize the savings to consumers from LMP reductions. In the Forward Capacity Market, LMP reductions during high-priced Shortage Events are offset by the Peak Energy Rent ("PER") payment adjustment to capacity resources. That is, when LMPs go down, capacity payments to capacity resources go up because the PER deduction to capacity payments is reduced.

- **Discouraging investment in renewable generation technologies that have low or no fuel costs.** A large portion of net revenues earned by many generation projects utilizing renewable resources (*e.g.*, wind, solar, etc.) is in the form of "energy rents"—*i.e.*, the difference between the LMP and the cost of production. Depressing LMPs below efficient market clearing levels would reduce the earnings of such resources. Because these resources have relatively low capacity values, a shift in available revenues from the energy market to the capacity market would reduce the overall incentive to invest in these resources.

- **Non-comparable treatment of generation technologies that reduce LMPs.** Paying demand resources on the basis of LMP reduction discriminates against other types of resources that also

reduce LMPs. For example, generators with low or zero short-run marginal costs (*e.g.*, nuclear resources and certain renewable resources such as wind) reduce the LMP when they operate. Allowing demand resources to receive both bill savings and full-LMP payment because of their LMP-reducing attributes discriminates against generators that receive only the LMP even though those generators also reduce LMPs across many hours.

- **Reducing the demand of some consumers below optimal levels.** By paying some consumers to reduce demand in order to reduce LMPs, the consumers receiving incentive payments may be encouraged to take economically inefficient actions such as deferring energy consumption the value of which exceeds the cost of producing energy.

- **Increasing the demand of other consumers above optimal levels.** If LMPs are reduced by paying some consumers to reduce demand, the remaining consumers who experience a price decrease are encouraged to increase demand, which negates at least some of the demand reductions achieved by the program.

- **Discouraging investment in higher capacity factor demand resources.** Depressing LMPs below market clearing levels by encouraging the use of demand response resources with marginal costs exceeding LMPs reduces the avoided cost of energy, which in turn reduces the

cost-effectiveness of higher capacity factor demand resources such as energy efficiency and base-load distributed generation. As indicated in the National Action Plan for Energy Efficiency:

> The most common primary measurement of energy efficiency cost-effectiveness is the TRC [total resource cost], followed closely by the SCT [societal cost test]. A positive TRC result indicates that the program will produce a net reduction in energy costs in the utility service territory over the lifetime of the program. The distributional tests (PCT [participant cost test], PACT [program administrator cost test], and RIM) are then used to indicate how different stakeholders are affected. *Historically, reliance on the RIM test has limited energy efficiency investment, as it is the most restrictive of the five cost-effectiveness tests.*[43]

Accordingly, ISO-NE strongly urges the Commission to reject an approach that determines cost-effectiveness of demand resources and associated incentive payments based on the RIM perspective. Rather, wise stewardship of society's resources requires that the cost-effectiveness of, and associated incentive payments to, demand resources be based on a total resource cost perspective.

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[43] National Action Plan for Energy Efficiency, at pp. ES-2 (emphasis added).

IV. THE PROPOSAL TO PAY FULL LMP IN ALL HOURS CAN LEAD TO SERIOUS MEASUREMENT AND VERIFICATION PROBLEMS

The Commission's proposal requires payment of the full LMP for reductions from expected levels of energy consumption in all hours. Estimating the "expected levels" of consumption, absent a day-ahead purchase requirement or other advance purchase requirement, requires calculation of a customer baseline. The requirement that resources be eligible for full LMP payment in all hours, however, makes baseline estimation a substantial challenge. No baseline estimation methodology that relies upon historical customer meter data can accurately and reliably estimate what an individual customer's energy usage pattern would have been if that customer responds frequently to price signals. Furthermore, statistical estimation of baselines could invite sophisticated market participants to strategically schedule load reduction events so as to manipulate the baseline calculation.

To achieve comparability between generation and demand resources participating in the energy markets, the accuracy and reliability of the energy resource quantity provided by demand resources should be similar to that of generators. Achieving such comparability, however, is a challenge for demand resources. Whereas measuring the energy output of a generator is straightforward—the output is measured using an interval meter—measuring the demand reduction produced by a demand response resource is not as straightforward. No device exists that directly mea-

sures energy usage that did not occur, let alone a device that measures reduced consumption of energy in response to price signals. Accordingly, demand reductions need to be measured relative to an estimated baseline. The actual metered consumption of a demand resource is compared to the estimated baseline to establish the amount by which the demand of a market participant was reduced in response to price signals.

Numerous reasonable baseline estimation methodologies currently exist. However, the baseline estimation methodologies of which ISO-NE is aware, which are used to settle load reductions provided by customers participating in demand response programs, rely upon statistical analysis of historical customer meter data. Such baseline estimation methodologies exclude from the computation those days in which load reductions are scheduled to occur. The purpose behind excluding days with scheduled load reduction events is to establish a pattern of energy usage on a "normal" day against which energy usage on an "event" day can be compared. However, if a market participant schedules demand reductions for many consecutive days, that means many days are excluded from the baseline calculation. As a result, baselines can become stale and may not truly estimate a customer's normal energy usage pattern. As mentioned above, no baseline estimation methodology that relies upon historical customer meter data can accurately and reliably estimate an individual customer's

normal energy usage pattern if that customer responds frequently to price signals.

Further, a sophisticated market participant could submit bids into the energy markets to strategically schedule load reduction events so as to manipulate the baseline calculation. "Adverse selection" and "moral hazard" give market participants incentives to inflate baseline estimates and extract program payments for essentially normal consumption behavior. Under adverse selection, customers have the incentive to selectively join a demand response program just before the end of their peak usage season. The baseline would be established using load data compiled during the customer's high usage season, which allows the customer to receive demand reduction payments as the customer's load naturally begins to decline because the customer is transitioning into its off-peak season.[44] Under moral hazard, customers may actively manipulate their load to create a higher-than-normal baseline and then receive payments for essentially normal consumption.[45] Behavior associated with adverse selec-

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[44] For example, a customer with high air conditioning usage may join a demand response program at the end of the summer season, and receive payments when its air conditioning load naturally subsides into the fall. A school may join a demand response program in the spring when the school is still in session, and then receive payments through the summer while the school is essentially unoccupied. Ski resorts may join the program just before the end of the snow-making season. A factory may join a program just before its planned seasonal shut down.

[45] For example, a customer with a behind-the-meter, base-load distributed generation unit could temporarily turn off the unit dur-

tion and moral hazard was observed in the DALRP in the fall of 2007, which prompted changes to the program rules so as to limit the hours in which a demand reduction offer could clear under the program.[46]

Additionally, a calculated baseline is not used symmetrically—*i.e.*, baselines are used to estimate reductions, but not increases, in expected energy consumption. As a result, a participant can receive payments for essentially no reduction in net energy usage. Participants on a *fixed retail rate* would be able to take advantage of the asymmetric use of calculated baselines in the following ways:

- A participant could reduce usage below its baseline in one hour and receive full-LMP payment for that reduction, but then increase usage above its baseline in an adjacent hour without having to pay the full LMP for its increased usage. If the adjacent hours have similar LMPs, such load shifting does not reduce overall energy usage or costs, yet the participant receives payments.
- If baselines are statistically estimated using hourly meter data from previous days, a participant can receive payment for essentially nor-

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ing which time it establishes a baseline. Once the baseline is established, the customer turns the unit back on to extract demand reduction payments.

[46] *See ISO New England Inc.*, Docket No. ER08-538-000; Filing of Changes to Day-Ahead Load Response Program (February 5, 2008).

mal consumption behavior through the natural day-to-day variation in load. For example, assume that the baseline is computed as the statistical average of metered loads from five previous days. If the load for a particular hour over the last five days was 5, 4, 3, 2, and 1 MW, the calculated baseline for the hour would be 3 MW. If the load continued to exhibit the same variation going forward, the participant could receive full-LMP payment on the days in which the load was 2 or 1 MW, but not be required to pay the full LMP when the load was 5 or 4 MW. Overall energy usage would not have changed, and this participant would not have to do anything differently to receive payments.

- A participant with multiple facilities in the same control area could establish baselines for each facility, and then shift production from one facility to another such that overall production and energy usage among all facilities does not change. The facilities with usage falling below its baseline, however, receive full-LMP payment whereas the facilities increasing usage above its baseline would not need to pay the full LMP for increased usage. By definition, overall energy usage would not have changed, yet the participant would receive payments for reduced usage.

There may be other ways in which participants on fixed retail rates could take advantage of the asymmetric use of baselines and receive payments for essentially no change in overall energy usage.

Finally, since baselines are estimates that are not directly observable—*i.e.*, baselines are used to estimate consumption that *did not* occur—it is difficult to verify the legitimacy of a claimed baseline estimate. To the extent that program participants actively modify their energy usage in response to changing LMP levels over many hours of the year, the accuracy of baseline estimates becomes increasingly unreliable.[47] To address this problem, it is necessary to limit the number of hours or days that a demand resource could clear in the energy market so that the customer's "normal" load can be estimated. This approach is utilized in the current ISO-NE price-response programs. Of course, this limits the number of hours that a demand response resource could clear the market, which is contrary to the Commission's proposed rule that demand resources be paid in all hours.

It is preferable to avoid the use of statistical analysis of historical usage data when establishing baselines for demand resources participating in the energy

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[47] While programs seeking to maximize price-responsiveness across many hours should avoid the use of statistically-estimated baselines, a statistically-estimated baseline can be an effective tool for measuring load reductions that occur infrequently. Research conducted by ISO-NE shows that the current baseline methodology has acceptable accuracy at an event day frequency of about 100 days per year. ISO-NE estimated that Real-Time Demand Response Resources participating in the Forward Capacity Market may be called between 12-26 days during the 2011/2012 Capacity Commitment Period. Therefore, ISO-NE concluded that its current baseline methodology is adequate for Real-Time Demand Response Resources participating in the Forward Capacity Market.

markets. Instead, baselines should comprise hourly MWh quantities acquired through the day-ahead energy market. The approach could be utilized with some other form of advanced purchase, but the discussion here is limited to the day-ahead energy market. This would allow payment in all hours and avoid the need to somehow restrict the hours of payment because of limitations in baseline estimation techniques. To the extent that prices in the day-ahead energy market exceed the cost of dispatching the participant's demand resource capability, the participant would simply not purchase the energy in the day-ahead energy market and would instead plan to deploy its demand resource capability for the next operating day. Deploying demand resources under such circumstances is cost-effective since LMPs exceed the cost of the demand resource.[48]

Formulating a baseline on the basis of a cleared financial position in the day-ahead energy market would not be subject to artificial constraints such as a minimum number of days for which meter data is needed to establish a customer baseline or a maximum number of days that a demand resource could clear to maintain baseline accuracy and reliability. Against such a baseline, the customer can sell any amount of energy in the form of a demand reduction into the

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[48] Of course, reducing purchases in the day-ahead energy market would also result in lower prices. If real-time LMPs decrease to a point below the cost of the demand resource, the participant could take advantage of such low prices by turning off its demand resource and consuming energy from the wholesale power grid.

real-time energy market at the full real-time LMP for any or all hours that it chooses not to consume.

Not requiring the participant to first purchase its expected energy requirements essentially allows the participant to sell energy into the grid which it did not have to first purchase and own. For example, if a consumer saves two gallons of gasoline by not using his car today and the price is $3.00/gallon, the consumer saves $6.00. The consumer cannot also expect to receive a payment of $6.00 unless he had previously purchased two gallons of gasoline which he does not use and instead sells to someone at the going price of $3.00/gallon. However, if this consumer did not previously purchase two gallons of gasoline, but is paid $6.00 for not consuming the two gallons, this consumer is being treated as though he is allowed to sell to the market two gallons of gasoline that he never possessed. In contrast to generation resources that physically inject energy into the wholesale power grid, demand resources physically reduce the withdrawal of energy from the wholesale power grid. As a result, allowing a participant with a demand resource to sell reduced energy usage like a supply of energy to the wholesale power grid in a manner comparable to a generator requires the participant to first purchase its expected energy usage before it can sell any unused energy back to the market for payment. To do so otherwise, like in the gasoline example, allows the participant to sell a quantity of energy back to the market which it never possessed. It is difficult to conceive of a well-functioning market for which market

participants are allowed to sell goods into the market for which they do not have entitlement.

Formulating a baseline on the basis of a cleared financial position in the day-ahead energy market complies with the Commission's proposed rule that demand resources be paid in all hours while maintaining baseline accuracy and reliability. Further, this approach affords participants with demand resources full flexibility with minimal ISO/RTO oversight. Rather than a one-size-fits-all baseline estimation approach, which may not work well with all types of demand resources, or an approach that allows demand resources to use "customized" baseline methodologies subject to ISO/RTO approval, which would be subject to gaming and be highly burdensome for ISOs and RTOs to administer, use of a participant's financial day-ahead energy market position as the baseline allows participants to establish any type of baseline that fits their individual circumstances with little need for ISO/RTO oversight.

V. THE PROPOSED RULE RAISES COST ALLOCATION ISSUES THAT MUST BE ADDRESSED

Unlike programs that require the day-ahead or other advance purchase of energy, approaches that pay demand resources like supply resources create a unique settlement problem. Because demand resources reduce demand, treatment of demand resources as a supply resource would create a settlement imbalance; payments in the energy markets due to suppliers, both generation and demand resources, would

exceed collections from consumers.[49] Allocation of these costs has been a subject of significant discussion in the New England stakeholder process. If the proposed rule is adopted, the Commission must address how payments to demand response providers will be allocated. Since the NOPR did not address this important issue, the Commission will need to propose further rules and seek comment before such rules can be implemented.

In a simple energy market in which supply consists of only generators and demand consists of only consumers, the allocation of energy market costs is straightforward. If a generator produces 100 MWh, that is because 100 MWh of load exists; therefore, settlement consists of paying the generator the market-clearing price for the 100 MWh it produced, and charging the consumers the same market-clearing price for the 100 MWh it consumed. Such an allocation is efficient and non-controversial because only those who consumed energy get charged and only those that produced energy get paid—those who did not consume do not get charged and those that did not produce do not get paid.

In contrast to a generator, however, if a demand resource produces 100 MWh as a supply resource, demand is simultaneously *reduced* by 100 MWh. Settlement in this situation is much more complicated because total supply (including generation and demand

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[49] This problem does not exist when baselines are established by financial positions in the day-ahead energy market.

resources) exceeds total demand by the amount of demand resources delivered in real time.[50] If the demand resource is paid the market-clearing price for 100 MWh of demand reduction produced, who should be charged to pay for the 100 MWh that had been eliminated? Payment of demand reductions as a supply resource requires ISOs/RTOs to address to whom the resulting cost ought to be allocated. Obviously, market participants have a financial stake in how payments to demand resources are allocated. Within New England, stakeholder discussions about this issue were nearly as controversial as the question of how much to pay for demand reductions. To address this issue, ISO-NE recommends that the Commission require that payments to demand response providers be allocated among market participants in a way that minimizes the overall cost impact on customers.

Under the general approach to meeting the Commission's goals advocated by ISO-NE, whereby the participant purchases its expected energy consumption

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[50] By treating demand reductions as a supply resource, if generators produce 1,000 MW of energy and demand response providers produce 100 MW of demand reductions in a particular hour, a total of 1,100 MW of supply would exist. Assuming an LMP of $100/MWh, suppliers (*i.e.*, both generators and demand response providers) would be owed a total of $110,000. However, only 1,000 MW of energy were consumed in that hour—recall that physical generation and load on the bulk power system must be equal in real time. If consumers are charged the same LMP for its metered consumption, only $100,000 would be collected, resulting in an under-collection of $10,000, which is equal to the payments owed to the demand response providers.

(*i.e.*, its baseline) at the day-ahead LMP and then is free to resell its position at the full real-time LMP, the cost allocation issue is automatically addressed within ISO-NE's current settlement algorithms. Entities taking a position in the energy markets would be financially responsible to pay for the positions taken, and any benefits produced by demand reductions would be accrued by those producing the demand reductions. Under ISO-NE's recommended approach, allocation of demand resource costs is efficient and non-controversial—those who consume energy get charged and only those who have an entitlement to energy but choose not to consume it get paid.

If the Commission nevertheless declines to require participants to purchase their expected energy requirements at the day-ahead LMP, adopts its rule as proposed, and/or utilizes statistically-estimated baselines rather than those based on the participant's day-ahead energy market position, the total amount paid to suppliers (generation and demand resources) at the full LMP would exceed collections from load-serving entities. In this instance, the ISOs/RTOs and the Commission would be faced with the difficult issue of determining how to allocate the costs associated with payments made to demand response providers.

There are numerous factors to consider in determining an appropriate allocation of these costs. A consumer that reduces energy consumption in real-time by utilizing its demand resource capability in response to high LMPs also reduces the amount of high-cost energy that its load-serving entity needs to pur-

chase from the wholesale market, which in turn reduces the costs incurred by that load-serving entity. However, the same reduction in consumption also affects the retail revenue of the load-serving entity—interrupted load means lower retail sales and thus lower retail revenues. Finally, and most importantly, uncertainty in the amount and timing of load reductions produced by demand resources introduces an additional element of risk in serving the load of consumers with demand resources, particularly if the consumer is charged a fixed retail rate by its load-serving entity. For example, a load-serving entity charging a fixed retail rate needs to incorporate into its rate a forecast of how much, and at what LMP level, demand response is likely to occur during the prospective period over which its rate is in effect. However, since the amount and timing of demand response is uncertain, the load-serving entity will likely charge a risk premium to address this uncertainty. Higher risk premiums ultimately result in higher retail rates charged to end-use customers.

Analysis conducted by ISO-NE indicates that different cost allocation schemes expose load-serving entities to different levels of risk that result from uncertainty in the level of and timing of demand reductions from demand resources. Higher risks result in higher retail rates and ultimately higher overall consumer bills. However, the level of the risk that needs to be hedged is also a function of the amount paid to demand response providers, whether a participant is required to purchase its expected energy requirements at the day-ahead LMP, and whether the participant's base-

line is based on its day-ahead energy market position. Because ISO-NE cannot presume the outcome of the NOPR proceeding with respect to these issues, it is difficult to recommend a specific cost allocation approach that would minimize the risks introduced by greater penetration of demand resources in the market. To guide ISO/RTO market rule development at the conclusion of the NOPR proceeding, ISO-NE recommends that the Commission require that market rules implementing the Commission's proposed rule allocate costs related to payments to demand response providers in a manner that minimizes cost impacts on final consumers.

If the Commission's rule is ultimately adopted, the simplest means of cost allocation is to split the costs resulting from payments to demand response providers into two components and charge those costs separately. The first component, the so-called LMP-G component, should be charged to the load-serving entity that is providing the energy to the end-use customer. The second component, the excess over the LMP-G (*i.e.*, the "G" component), should be charged to network load, which is the transmission owner portion of the bill. The transmission owner is best situated to simply pass this charge through as part of its rates to all customers to pay the excess costs. Analysis conducted by ISO-NE indicates that splitting the costs between load-serving entities and transmission owners as described above minimizes cost impacts on final customers. This proposal, however, should not be adopted until the Commission has conducted a full proceeding to discuss cost allocation.

VI. PAYMENT OF LMP LESS THE RETAIL GENERATION RATE CAN BE EFFICIENT

If ISO-NE's recommendations for how to implement the Commission's suggested payment of the full LMP in all hours are not adopted, other approaches that produce economically-efficient outcomes ought to be considered by the Commission. These alternative approaches, however, may require the Commission to consider the complex and controversial issues of determining accurate and reliable baselines and allocating costs associated with payments to demand resources.

One such approach would be to pay demand response providers that reduce demand the LMP less the retail generation rate ("LMP-G"). For example, assume a 10 MWh retail customer with a fixed 10¢/kWh retail generation rate and a demand resource with a marginal cost of 20¢/kWh. When the LMP is $300/MWh (*i.e.*, 30¢/kWh), dispatch of the demand resource is cost effective. As demonstrated previously, the dispatch of the demand resource is cost-effective whenever the marginal cost of the demand resource is less than or equal to the LMP. However, given the retail customer's fixed rate of 10¢/kWh, the retail customer has no incentive to dispatch its demand resource, because it could receive energy at a lower cost than the cost of dispatching its demand resource.

However, if this customer were offered an incentive payment of LMP less the retail generation rate, the customer would be paid 20¢/kWh for dispatching its demand resource (*i.e.*, the 30¢/kWh LMP less the fixed

10¢/kWh retail generation rate = 20¢/kWh incentive payment). By dispatching its demand resource, the customer reduces its net energy bill by $1,000. That is, the customer could purchase its energy requirements at its fixed retail rate of 10¢/kWh for a total bill of $1,000 (*i.e.*, 10¢/kWh retail rate x 10 MWh = $1,000). However, the customer's net energy bill would be $0 if it dispatched its demand resource. This is because the dispatch of the demand resource reduces the customer's retail load to 0 kWh, so the customer's retail bill is likewise $0. Further, the incentive payment offsets the cost of dispatching the demand resource (*i.e.*, [20¢/kWh incentive payment – 20¢/kWh demand resource marginal cost] x 10 MWh = $0). Accordingly, the incentive payment of LMP less the retail generation rate incents the dispatch of a cost-effective demand resource.[51]

Paying LMP less the retail generation rate points to a solution for the cost allocation problem. If this

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[51] Because the retail customer still receives its energy commodity at a fixed retail rate under the scenario described here, the customer receives no incentive to increase its consumption in periods with low LMPs. While the approach described here produces an economically efficient result during hours in which LMPs exceed the retail generation rate, it is not as efficient as the approach described in Section IV and V of these comments whereby consumers or their agents purchase the consumer's expected usage and adjust their actual usage in real time as real-time conditions warrant. All price-responsive demand approaches that pay only for *load reductions* fail to realize the gains in customer value and economic efficiency from increasing load during hours with low LMPs.

payment rate is adopted, costs of payments to demand resource providers should be allocated to the load-serving entity whose load was reduced by the demand resource. Because the load-serving entity serving this customer experiences a net increase in wholesale market revenue in the amount of the reduced load times the difference between the real-time LMP less its retail generation rate,[52] the load-serving entity whose load was reduced by demand resources is in the best position to finance these incentive payments, and it could do so without having to raise its retail rates. Finally, since demand resource costs are not allocated to other load-serving entities, these other load-serving entities do not have to increase their rates to finance demand resource costs. Most notably, the stakeholders representing New England's load-serving entities agreed with ISO-NE that they should receive a direct allocation of demand resource costs to the extent that such costs were based on the LMP less the actual retail generation rates charged by such load-serving entities.

Under this approach, where demand response providers are paid the LMP less the retail generation rate

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[52] Under this approach, the load-serving entity sells the demand resource's unused energy back to the real-time energy market at the real-time LMP. The load-serving entity also experiences an erosion of its retail revenue equal to its retail generation rate. However, if the payment to the demand response provider is equal to the LMP less the retail generation rate, the load-serving entity whose load was reduced by the demand response is in a position to fully finance the payment to the demand response provider without having to increase its retail rates.

for demand reductions, a statistically-estimated customer baseline appears to be needed, given that the entity taking the position in the wholesale energy market on behalf of the customer (*i.e.*, the load-serving entity) and the entity working with the customer to utilize its demand resource capability (*e.g.*, the demand response provider) are likely to be different entities. However, because demand response providers would not likely produce demand reductions when LMPs are less than the retail generation rate, and since retail generation rates would likely be higher than LMPs for a majority of hours in the year, statistically-estimated customer baselines are likely to be reasonable estimates of a customer's normal energy consumption behavior.

Some stakeholders may argue that the incentive payment to a participant in the energy market with a demand resource not be reduced by the retail generation rate. But, as noted earlier, this can lead to the dispatch of demand resources that are not cost effective. For example, assume the same customer with the same demand resource as above (*i.e.*, a 10 MWh retail customer with a fixed 10¢/kWh retail generation rate and a demand resource with a marginal cost of 20¢/kWh). If the LMP were $150/MWh, the customer could reduce its net energy bill by dispatching its demand resource even though the cost of the demand resource (20¢/kWh or $200/MWh) is greater than the cost of the marginal resource in the market represented by the LMP ($150/MWh). If the customer does not dispatch its demand resource, it would incur a cost of $1,000 for consuming 10 MWh of energy (*i.e.*,

10¢/kWh retail rate x 10 MWh = $1,000). By dispatching its demand resource, the customer would reduce its net energy bill to $500 (*i.e.*, [$200/MWh demand resource marginal cost $150/MWh incentive payment] x 10 MWh = $500). Accordingly, if the payment to the demand resource is not reduced by the retail generation rate, the customer is given the incentive to dispatch its $200/MWh demand resource, which displaces a $150/MWh marginal resource in the market. This is not cost effective and does not result in comparable treatment of resources in the energy markets. Accordingly, a payment rate of the LMP less the retail generation rate is efficient and consistent with a total resource cost perspective.

An approach based on the LMP less the retail generation rate combined with the use of a statistically-estimated baseline was being developed in the New England stakeholder process prior to the Commission's initiation of the NOPR proceeding. Whether the Commission modifies the NOPR's full LMP payment principle or not, ISO-NE recommends that the Commission require that any resulting costs associated with payments to demand response resources be allocated to market participants so as to minimize cost impacts on final consumers.

ISO-NE is also aware of other approaches that are consistent with a total resource cost perspective. For example, Professor William W. Hogan developed an "unbundled transaction model" which also appears

consistent with a total resource cost perspective.[53] Professor Hogan (for the ISO/RTO Council) and ISO-NE's Internal Market Monitor will be submitting comments in the NOPR proceeding, which evaluate various alternatives to achieving price-responsive demand in the energy markets.[54] Because there is more than one approach to achieve cost-effective usage of resources in the energy market while achieving comparable treatment between generation and demand resources in the energy markets, the Commission should allow each region to develop an approach that suits its particular circumstances. Such approaches, however, should be consistent with a total resource cost perspective, address the baseline issue adequately, and minimize cost impacts on final consumers.

VII. CONCLUSION

In its current form, the proposed rule does not produce an efficient market outcome—it will encourage the dispatch of higher-cost demand resources in place of lower-cost generation in the energy markets. The proposed rule will have many undesirable effects, including higher consumer costs in the long-run. Further, the proposed rule appears to be based on the assumption that demand resources and generators

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[53] *See* Motion for Leave to Answer and Answer of the Electric Power Supply Association and White Paper by Professor William W. Hogan, Docket No. EL09-68-000 (October 30, 2009).

[54] *See* Hogan Paper included with ISO/RTO Council comments being filed today in this proceeding. *See also* the comments of the ISO-NE Internal Market Monitor being filed today in this proceeding.

have similar financial motivations and would participate in the energy market in the same way. This assumption, however, is not true. While generators are motivated to participate in energy markets by earning revenues in excess of costs, demand response providers and the consumers they serve are motivated to participate in energy markets by reducing net energy bills. The fundamental difference between generators and demand resources warrants different treatment in the energy markets to ensure comparable incentives for all energy resources, increase the economic efficiency of energy markets, and reduce total resource costs. Finally, the proposed rule introduces substantial baseline estimation and cost allocation problems, neither of which is addressed in the NOPR. Accordingly, ISO-NE strongly urges the Commission ***not*** to promulgate the proposed rule in its current form.

ISO-NE's views concerning appropriate demand resource program design and the fundamental goal of economic efficiency is both consistent with the design criteria applied to each of the ISO-administered markets and with decades of regulatory policy. An economically-efficient market allocates society's limited resources to their most productive and valuable uses. Rather than promulgating the proposed rule, ISO-NE encourages the Commission to formulate, and permit implementation of, market rules that are consistent with basic principles of economic efficiency. While these comments demonstrated how the proposed rule creates inefficiencies, these comments also suggested how these inefficiencies can be corrected.

Further, these comments suggest an approach that establishes accurate and reliable baselines through day-ahead energy purchases, which permits the payment of the full LMP in all hours in which consumption was reduced from expected levels in response to price signals. Finally, these comments ask that the Commission require costs associated with payments to demand response providers be allocated among market participants so as to minimize their impact on end-use consumers.

If the Commission does not require demand response providers to purchase their power in advance before allowing the demand response provider to sell energy into the market in the form of demand reductions, then it is difficult to design an approach in which paying full LMP in all hours for demand reductions is economically efficient. Under approaches developed by ISO-NE as part of its current price-responsive demand stakeholder process, advance purchases are not required. However, efficiency is achieved under this approach by paying the LMP minus the generation portion of the customer's retail rate. This approach also requires the calculation of a customer baseline, which has inherent incentive problems, but could be effectively implemented since fixed retail generation rates are likely to exceed LMPs most of the time, making statistical estimation of "normal" consumption levels more reliable and accurate. Such an approach also results in costs related to payments to demand response providers that must be allocated to market participants in some fashion. Commission guidance on cost allocation in its final rule would assist

the ISOs/RTOs in the development of market rules to govern demand resource participation in the energy markets. ISO-NE recommends that the Commission require that such costs be allocated among market participants to minimize cost impacts on end-use consumers.

ISO-NE appreciates this opportunity to address the Commission's proposed rule, and urges the Commission to promulgate a final rule that is consistent with these comments.

Respectfully submitted,

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May 13, 2010

UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Docket Nos.: RM10-17-000, EL09-68-000

DEMAND RESPONSE COMPENSATION IN ORGANIZED WHOLESALE ENERGY MARKETS

May 13, 2010

COMMENTS OF THE MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.

In accordance with the Federal Energy Regulatory Commission's ("Commission") request for comments in the subject proceeding, the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") respectfully submits the following comments in response to the Commission's Notice of Proposed Rulemaking ("NOPR") regarding compensation of demand response resources ("DRR"). The Midwest ISO also supports the white paper being filed by the ISO/RTO Council in this proceeding,[1] with clarifying comments as noted below.

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[1] William W. Hogan, *Demand Response Pricing in Organized Wholesale Markets*, Prepared for ISO/RTO Council Comments on Demand Response Compensation in Organized Wholesale Energy Markets, Docket No. RM10-17-000, (May 13, 2010) ("Hogan White Paper").

I. INTRODUCTION

On March 18, 2010, the Commission issued a NOPR addressing how providers of demand response ("DR") should be compensated. In the NOPR, the Commission proposed that Independent System Operators and Regional Transmission Organizations ("ISOs/RTOs") should implement tariff provisions so that DR providers that participate in energy markets by reducing consumption in response to price signals would be paid the hourly market energy price for each MWh of their curtailed energy usage in that hour.

On October 2, 2009, the Midwest ISO submitted its Order No. 719 compliance filing in which it presented the Midwest ISO's proposal for accommodating the participation of Aggregators of Retail Customers ("ARCs") in its wholesale markets.[2] The proposal specifically described a method for compensating Demand Response Resources ("DRRs") sponsored by both ARCs and Load-Serving Entities ("LSEs"); the proposed method is equally valid for all DRRs regardless of market participant status. The Midwest ISO believes that its proposed compensation methods are fully consistent with the rule change that the Commission describes in the NOPR while also addressing compensation issues beyond the scope of the NOPR. For example, the NOPR narrowly addresses compensation of DRRs without considering how the RTO will remain

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[2] *Midwest Independent Transmission System Operator, Inc.*, Filing re Aggregators of Retail Customers, Docket No. ER10-26-000 (Oct. 2, 2009). This filing is currently pending Commission approval.

revenue neutral and which market participants will incur charges to cover the DRR payments. These are important issues that need to be addressed contemporaneously with the subject DRR compensation issues.

The next section of these comments describes the Midwest ISO's proposal for compensating DRRs. Section III then describes how the Midwest ISO has proposed to recover those DRR compensation payments. Section IV presents an approach to demand response that is not based on the "sale for resale" paradigm that some entities have relied upon when developing proposals for compensating DRRs. Section V addresses each of the specific questions the Commission has raised in the NOPR. Section VI presents the Midwest ISO's concluding statements.

II. MIDWEST ISO PROPOSAL FOR COMPENSATING DEMAND RESPONSE RESOURCES

The Midwest ISO proposed to compensate DRRs through an initial payment of Locational Marginal Prices ("LMP") for the energy foregone through the load reduction. Additionally, under the Midwest ISO's proposal, the Market Participant ("MP")[3] employing the DRR ("DR provider") will incur a charge for the Marginal Foregone Retail Rate ("MFRR") applicable to the retail customers that produced the load reduction.

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[3] Capitalized terms not otherwise defined herein have the meanings ascribed thereto in Section 1 of the Tariff.

As proposed by the Midwest ISO, the DR provider would be paid the hourly LMP at the DRR's Commercial Pricing Node ("CP Node") for each MWh delivered. The hourly LMP at any CP Node is the MWh weighted-average of the hourly LMPs at the physical locations on the transmission system where the retail customers that produced the load reductions withdraw their energy.

The Midwest ISO would charge each DR provider the MFRR[4] applicable to the retail customers that delivered the demand reduction in that hour. The MFRR[5] is a proxy for the average price that these retail customers avoided paying to their LSE for the energy they would have consumed but for their load reductions. Conceptually, one can think of this as a charge for the energy the DRR would have consumed but instead sold into the market. The MFRR payments will be credited to the LSE serving the retail

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[4] The Midwest ISO has the capability to update the MFRR rate on an hourly basis, if necessary, and the Midwest ISO can calculate Actual Energy Injections based upon meter data provided by the Meter Data Management Agent ("MDMA").

[5] The Hogan White Paper advocates using some variant of "LMP-G" as appropriate compensation of DRR assets. The Midwest ISO's proposal to charge DR providers based on the MFRR is consistent with Professor Hogan's view. In addition, the Midwest ISO's proposal recognizes that the RERRA has the authority to determine whether or not retail customers under its jurisdiction will be allowed to participate as DR providers in the Midwest ISO's markets and respects these rights. The RERRA is responsible for determining an MFRR for each demand response asset that the DR provider has registered with the Midwest ISO.

customers that sold their demand reductions through the DR provider.

The Relevant Electric Retail Regulatory Authority ("RERRA") having jurisdiction over the LSE whose retail customers delivered a load reduction would provide the numerical value for the MFRR associated with that load reduction. The Midwest ISO strongly believes that quantifying the MFRRs is the purview of the RERRA; the Midwest ISO will only provide a settlement service on behalf of the RERRAs by applying their MFRR adjustments to DRR compensation payments.

Certainly, there are other ways to make MFRR adjustments. Initially, the Midwest ISO proposed to pay DR providers the full hourly LMPs for their load reductions and leave adjustments for avoided retail payments to the RERRAs to implement at the retail level. For example, one option would be for the RERRA to require the DR provider to directly pay the LSE for the foregone energy as a precondition to the DR provider gaining access to the retail customers of the RERRA's jurisdictional LSEs. This is essentially the model adopted by the California Public Utilities Commission.[6] The Midwest ISO rejected this option primarily because the RERRAs within its footprint were concerned about having the entire burden of retail revenue recovery shifted to them.

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[6] *California Independent System Operator*, Tariff Amendment to Implement Proxy Demand Response Product, Docket No. ER10-765-000, (Feb. 16, 2010).

By charging a DR provider the MFRR for the energy it sells into the market, it might appear that the Midwest ISO is paying less than LMP for that energy. In fact, as described in more detail below, the Midwest ISO is proposing to pay the DR provider full LMP for its energy, while simultaneously transferring from the MP to the LSE the marginal retail rate that its customers avoided paying their LSE for that same energy.

III. MIDWEST ISO PROPOSAL FOR RECOVERING DRR COMPENSATION PAYMENTS

The Midwest ISO, in its Order No. 719 compliance filing, proposed to recover the LMP payments that it makes to a DR provider by charging those payments to the LSE whose retail customers delivered the load reductions that the DR provider sold into the wholesale market. The Midwest ISO and its stakeholders preferred this targeted recovery option because:

- It places the LSE in the same financial position it would be in if the load reductions had not occurred;
- It avoids the creation of cross-subsidies among LSEs and their retail customers;
- It avoids increasing the energy "uplift" charges that reduce market economic efficiency by raising the prices that consumers pay for the energy above the marginal cost of producing that energy.

Under the Midwest ISO's proposal, the targeted LSE is made financially whole because it pays the

same amount for energy irrespective of whether the demand reductions occurred.[7] This is because the Midwest ISO settlement system will "reconstitute" the LSE's hourly loads by adding back the MWh of load reductions and debiting the LSE for the reconstituted loads at the prevailing LMPs. Load reconstitution has the added advantage of indemnifying the LSE from charges for Real-Time load deviations from its Day-Ahead positions that were solely caused by the demand response delivered by its retail customers, rather than by any actions of the LSE.

The alternative to such targeted recovery of DRR compensation payments is through energy "uplift" payments. For the three reasons cited above, the Midwest ISO and its stakeholders overwhelmingly rejected such recovery. In particular, the LSEs strongly opposed any increases in "uplift" charges because such a proposal would have violated the principle of cost causality.

IV. A NEW DEMAND RESPONSE PARADIGM

The Midwest ISO is aware that the Commission no longer relies on its earlier characterization of demand response as a "sale for resale" and the Commission now views demand response as a:

> reduction in the consumption of electric energy by customers in response to an increase in the

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[7] In addition, the Midwest ISO settlement system reimburses the LSE for the retail revenues it lost from its customers' load reductions.

price of electric energy or to incentive payments designed to induce lower consumption[.][8]

The Midwest ISO fully agrees with this new paradigm and the Midwest ISO's Order No. 719 compliance filing is consistent with this paradigm. The Midwest ISO believes that its approach comports with physical and economic reality.

In general, retail tariffs endow customers with the right to buy energy at a fixed, predetermined price in any given hour regardless of the costs their LSEs must incur to produce or procure that energy. This is analogous to granting each customer a quantity of "call options" on electric energy where the option "strike price" is determined by the variable energy rates in that customer's retail tariff. When a customer reduces its load in return for payment from a DR provider, the customer effectively sells some of its unexercised call options to the DR provider. The DR provider then sells these options through the ISO/RTO power pool market. The ISO/RTO includes these options as supply offers in its security constrained economic dispatch, which makes the offers available to one or more buyers participating in its day-ahead and/or real-time energy markets.

The appropriate compensation for the ISO/RTO to pay a DR provider for one of these unexercised call options (*i.e.*, for its demand response) should be the economic value of the option, which is determined by the highest price any market participant would pay for

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[8] *EnergyConnect, Inc.*, 130 FERC ¶ 61,031, P 31 (2010).

it. The wholesale buyer that has the most to gain from any given unexercised call option is the LSE whose retail customer sold that call option because that LSE will avoid having to buy at LMP the energy underlying the option while only losing the revenues the customer avoids paying under its retail tariff.[9] No other single market participant will gain as much from the call option going unexercised; consequently, the competitive market price for the call option is LMP minus the marginal price in the retail customer's tariff, *i.e.*, the MFRR. By recognizing that the demand response delivered by a DR provider is tantamount to the ISO/RTO as the market administrator arranging for the buying and selling of call options on energy, the dual issues of how much to compensate DR providers and how to recover those payments are simultaneously resolved.

V. RESPONSES TO SPECIFIC QUESTIONS

The Commission has requested comments in response to nine specific questions raised in the NOPR. Each question is presented below, followed by the Midwest ISO's response.

1. Commenters may address whether current compensation for demand response providers acting as a resource in the organized wholesale energy markets is adequately procuring demand response.

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[9] Obviously the LMP will be higher than the avoided retail tariff rate, otherwise the retail customer would have no incentive to reduce its consumption of energy.

As of March 24, 2010, the Midwest ISO had 2,464 MW registered to provide economic demand response, in the Day-Ahead and Real-Time energy markets, all of which are DRRs sponsored by LSEs.[10] Thus, the Midwest ISO believes that the compensation offered to DR providers under its current and proposed (with ARC implementation) Tariff is, appropriate to incentivize demand response. Although higher DRR compensation payments would undoubtedly attract more demand response, such a result is not necessarily the most economic or the most efficient result. DRR compensation should be designed to only attract demand response that is *cost-beneficial* and this principle will only be achieved if the compensation reflects the net economic benefit that each retail customer foregoes when it reduces its load. The Midwest ISO submits that the DRR compensation proposal described in the Midwest ISO's Order No. 719 compliance filing satisfies that requirement and thus is both adequate and appropriate to attract cost-beneficial demand response.

For example, in 2008, PJM experienced a 37 percent drop in cleared economic demand response after it eliminated demand response "subsidy" (incentive) payments. The Midwest ISO understands that much of that lost demand response was from large commer-

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[10] These DRRs are all types of demand response resources; no behind-the-meter-generation is included in this figure. These assets are all sponsored by LSEs, in part, because the proposed tariff language to accommodate ARC participation is currently pending before the Commission.

cial and industrial customers, which employed LMP-based tariffs. When PJM paid these customers full LMP they effectively received *twice* as much compensation as they would have received under an economically efficient compensation scheme.[11] It should not come as a surprise that some demand response customers lost interest in providing demand response when their total compensation was cut in half, but cut to a level that more appropriately reflects its value.

To illustrate just how lucrative PJM's economic demand response program was for these customers, consider the following example. Suppose a large industrial facility decided to reduce its demand to 50 percent of its Customer Baseline. PJM formerly would pay the customer LMP for its demand reduction and the customer would pay that same LMP back to its LSE for the remaining half of their demand. The net result would be that the customer would pay *nothing* for the electricity it consumed!

In light of such potentially ludicrous outcomes, the Commission should consider a proposed rule change that would require ISOs/RTOs to pay DR providers a "market price" that incorporates the full LMP but also appropriately considers the payments that a DR provider's customers avoided making through their retail tariffs when demand was reduced. Such a rule

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[11] These customers were paid LMP directly plus avoided paying LMP to their service providers, which equals two (2) times LMP compensation.

change would appropriately encourage demand response without overly subsidizing such actions.

2. Comment on alternative approaches to compensating demand response resources participating in organized wholesale energy markets, and the merit of those approaches in comparison to the one proposed in the NOPR.

There are many alternate approaches to DRR compensation, all of which are based upon what is added to or deducted from LMP. The Midwest ISO's proposal for compensating DR providers ultimately deducts the MFRR applicable to the DR provider's retail customers from the LMP in calculating DRR compensation. However, this adjustment to LMP is done as a settlement service offered to the LSEs that are Midwest ISO Market Participants.

In testimony that accompanied the Order No. 719 compliance filing, Mr. Michael Robinson stated:

> Paying an ARC the LMP minus MFRR for each MWh of energy it injects into the markets is actually two separate transactions that take place simultaneously. First the ARC is compensated the LMP for each MWh of energy it injected. Then the ARC is charged the MFRR for that same energy to recover the revenues that its customers

avoided paying to their LSEs for the energy they injected through the ARC.[12]

Paying the DR provider 'LMP minus MFRR' properly reflects the fact that the retail customers represented by the DR provider have a contractual right to purchase energy at the MFRR from the LSE, as well as the right to either consume or not consume such energy.

One important issue related to DRR compensation, which the NOPR only addresses tangentially, is how the RTO/ISO is able to recover the DRR payments. As described earlier, the Midwest ISO recovers these payments from the LSE whose retail customers provided the demand reductions that the DR provider sold into the energy market. This focused recovery avoids creating cross-subsidies among the LSEs and also avoids increasing the energy uplift charges.

3. Comment on whether a reduction in consumption is comparable to an increase in electricity production for purposes of balancing supply and demand, and whether, therefore, demand response providers and generators should receive comparable compensation.

A reduction in consumption can be comparable to an increase in production for purposes of balancing supply and demand. If the DR provider has purchased a commensurate amount of load in the Day-Ahead market, then it is selling back its position in the Real-Time

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[12] *Midwest Independent Transmission System Operator, Inc.*, Prepared Direct Testimony of Michael Robinson filed on behalf of the Midwest ISO, at p. 15 (2009) ("Robinson Testimony").

market. The MP purchased its load at day-ahead LMPs, and sold it back as a DRR load reduction at real-time LMPs. The Day-Ahead market solution would ensure energy balance. A reduction in consumption is not comparable to an increase in production for purposes of balancing supply and demand (and also for ensuring revenue adequacy from the RTO's perspective) when neither the DR provider, nor the LSE with the obligation to serve the load behind the DRR asset has a day-ahead position. Suppose we expect load to increase by 20 MW in the next 5 minute interval and suppose that we dispatch a DRR asset to meet that load increase. If the load behind the DRR asset was going to start withdrawing energy over the next 5 minute interval but had not prior to the dispatch, then deploying the DRR asset does not ensure meeting the energy balance. The RTO would still have to call on additional generation to meet the load increase. This creates revenue inadequacy issues that have been addressed completely in the Midwest ISO ARC filing referenced above.

But even the physical equivalence of these two types of resources does not mean that they both deserve to receive comparable compensation. One resource delivers energy; the other does not.[13] Because demand response does not deliver energy, prices in the energy markets are not indicative of the compensation that DR providers should receive for their so-called "Negawatts." As the option pricing analysis pre-

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[13] As noted above, the Commission recently affirmed that demand response is not a resale of energy. *See supra* n.8.

sented in Section IV of these comments revealed, the appropriate price that an ISO/RTO should pay a DR provider is LMP minus the applicable MFRR. The Midwest ISO's Order No. 719 proposal arrives at the same conclusion.

Professor Alfred Kahn's statements that the NOPR cited also support this conclusion:

> the purpose and result here is to induce consumers to behave as they would if the market mechanisms alone were capable of rewarding them directly for efficient economizing.
>
> The (incremental) costs saved by curtailments in demand clearly will be full LMP—including the marginal costs of generation. So, in the end, full LMP inducement is the economically correct one.[14]

Professor Kahn's reference to the *"full LMP inducement"* is not synonymous with *paying full LMP* to a demand response resource. The retail customer making a decision regarding whether to reduce its load, and by how much, should receive an inducement equal to the sum of the payment it collects from the DR provider plus its saving from avoiding payment for the foregone energy at the marginal rate in its retail tariff. In other words:

> Retail Customer' Total Inducement = DRR Payment + MFRR Professor Kahn correctly states, this inducement should be the "full LMP[,]" so:

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[14] Comments of Alfred E. Kahn, at p. 4.

Retail Customer's Total Inducement = LMP = DRR Payment + MFR Because DRR Payment = LMP-MFRR, then LMP = (LMP-MFRR) + MFRR.[15]

4. Comment on whether paying LMP to demand response resources is comparable compensation or is more or less than comparable to compensation paid to generation in the ISO and RTO energy markets.

Paying LMP to DR providers is comparable to compensation paid to generation. The Midwest ISO addressed this issue in the Prepared Direct Testimony of Michael Robinson, which was part of the Midwest ISO's Order No. 719 compliance filing and referenced above. There, Mr. Robinson stated:

> In order to treat a demand response resource comparably with a power producer, the Midwest ISO must pay both types of resources the same price for each MWh of energy they "inject" into the transmission system. That price is the LMP at the demand response provider's or power producer's CPNode. The LMP reflects the value to the market in meeting the next MWh of load at each CPNode. However, to achieve comparability be-

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[15] Of course, the DR provider may keep part of the energy payment it receives from the ISO/RTO to cover its administrative costs and profit margin, which will result in a less than optimal amount of demand response. Alternatively, the DR provider can cover its costs and profit margin through fixed monthly subscription charges that would not distort the retail customers' demand response decisions. This is an important market design issue that the Commission has not raised in this NOPR.

tween the two resource types the MFRR must be subtracted from the LMP paid to an ARC for its customers' injected energy.

When a power producer injects energy into the transmission system, it owns that energy, because it either produced it with its own generator, or purchased it from another source. In contrast, when an ARC injects energy into the transmission system, it is not actually delivering additional energy; rather, it is reallocating energy that is already present in the system or reducing the need for an incremental amount to support the energy balance. So, what the ARC is selling is a bundle of rights of its retail customers to purchase the energy from their respective LSEs at the energy prices in their retail tariffs, *i.e.*, at the MFRR. Each retail customer's meter only records the energy that the customer actually consumed so that customer avoids paying for the energy it makes available for its ARC to sell. Consequently, the retail customer and its ARC must first buy the energy from the customers' LSE at the appropriate retail tariff price, or MFRR, in order to legitimately resell it in Midwest ISO markets.

Charging an ARC the MFRR for its injected energy has proven to be a source of confusion because, to many people, it appears as if the Midwest ISO is paying less than LMP for that energy. In reality, it is paying full LMP for the energy, but is collect-

ing the avoided purchase revenues on behalf of the LSEs that are entitled to be paid for that energy.[16]

Therefore, paying a DR provider the LMP minus MFRR is comparable to what generators are paid for producing energy.

5. Comment on whether payment of LMP should apply to all hours, and, if not, the criteria that should be used for establishing the hours when LMP should apply.

The Midwest ISO's position is that compensation for demand response should reflect the economic value of the demand reductions regardless of when they occur—even if they occur in the off-peak hours. The Midwest ISO supports a consistent and economically efficient approach that can be applied to all hours; the Midwest ISO does not support exemption from payments for any specific hours.

An interesting issue arises regarding compensation for a load reduction that results from the retail customer shifting its consumption from a peak (*i.e.*, high-LMP) hour to an off-peak (low-LMP) hour. While the LMP—MFRR methodology is the economically efficient price to pay a retail customer for energy not consumed in an hour when LMP exceeds the customer's MFRR, the methodology may undercompensate the customer for energy shifted to an hour when LMP is less than the customer's MFRR. Such load increases during hours of low demand would pro-

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[16] Robinson Testimony, p. 13, *et seq.*

vide the system operator with operational flexibility and could ease the need for decommitting large base load generating plants that have reach their minimum-load limits. As more power generated by wind resources enters the Midwest ISO system, such operational flexibility will become increasing valuable. The Midwest ISO suggests that additional analysis of this issue be undertaken.

6. Comment on whether requiring payment of LMP is appropriate across all ISOs and RTOs, or whether variations among ISOs and RTOs justify varying levels of demand response resource compensation.

The Midwest ISO's proposal for compensating DRRs is appropriate and economically efficient, assuming that the LMPs truly capture all of the costs associated with power production and delivery. To the extent that these costs are not fully internalized, then the amount of demand response induced by the DRR compensation will fall short of the optimum levels. Because external costs are likely to vary regionally, an argument can be made for allowing regional variations in the way that ISOs/RTOs compensate DR providers.

Given the existence of externalities, particularly green house gas emissions, it is tempting to conclude that overcompensating demand response by paying full LMP would be justified. This, however, is not optimal. Such broad social issues should be addressed outside of the FERC rate making venue. Including fixed cost adders in wholesale rates to account for external costs that have not been specifically quantified

and that can vary unpredictably would adversely affect economic efficiency and would most likely not satisfy the Federal Power Act's just and reasonable standards.

The Midwest ISO submits that an economically efficient DRR compensation method that is based upon demonstrated costs and benefits should be adopted for the purpose of establishing consistency across the nation.

7. Comment on whether the Commission should allow regional variations for an ISO or RTO that does not seek to compensate demand response resources participating in the organized wholesale energy market.

The Commission should allow regional variations when determining whether or not an ISO/RTO must implement an economic demand response program. Accounting for regional differences would not necessarily be harmful, particularly given the unique role of RERRAs regarding the participation of DRRs within their jurisdictions.

One possible reason why an ISO/RTO might choose to not directly compensate DRRs is that the LSEs participating in its markets may have put in place retail tariffs that substantially reflect the advantages of price-responsive demand response. The existence of such tariffs would tend to eliminate the need for economic demand response programs.

As many prominent energy economists have pointed out, economic demand response programs only exist to

compensate for the disconnect between retail and wholesale rates. Fixing retail tariffs is an obvious and more cost-effective alternative to economic demand response programs. Interestingly, PJM has publicly stated that retail price response demand that "is the ultimate solution to demand participation."[17]

The Midwest ISO urges the Commission to encourage efficient pricing for compensation of demand resource but in doing so continue to recognize regional differences.

8. Comment on whether, and under what circumstances, the Commission should conduct periodic reviews of demand response compensation and the criteria that should be used in making such assessments.

The Midwest ISO supports a Commission policy regarding compensation for DRR that recognizes the benefits of allowing wholesale markets to freely evolve with minimum federal intervention. The Midwest ISO suggests that an annual assessment of DR compensation protocols would be reasonable.

The primary criterion used to assess the methods for compensating DR providers should be economic efficiency and fairness. First, the Commission should evaluate each DRR compensation scheme from the

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[17] Statement of Terry Boston, President and CEO, PJM Interconnection, L.L.C. on behalf of the PJM Board of Managers, "Demand Response in the PJM Markets," June 26, 2009, *available at*: http://www.pjm.com/~/media/about-pjm/newsroom/2009-releases/20090626-pjm-board-statement-regarding-dr-in-pjm-markets.ashx.

perspective of whether it maximizes the total collective benefits for all market participants. Second, the Commission should assess whether those benefits, and the associated costs, are fairly allocated among the market participants based on the principle of causality. To the greatest extent practicable, each market participant should be charged for the costs it imposes and also should enjoy the benefits it creates through its actions.

9. Comment on whether terms such as "expected levels," "price signals," and "market prices" are sufficiently defined in the Commission's proposed regulations.

The Midwest ISO respectfully requests that the Commission define each of the aforementioned terms because they have different meanings in different regions and contexts. For example, "expected levels" of energy consumption is a statistical term employed in measurement and verification methodologies. Regarding "market prices," and "price signals" there are many different types, *e.g.*, Day-Ahead LMPs, Real-Time LMPs; five-minute LMPs; hourly-integrated LMPs *etc.* In addition, the price signals often referred to in demand response are not market prices but rather are contractual prices passed through to retail customers by an ARC. Lastly, all of these terms should be consistent with NAESB definitions. The Commission should eliminate the ambiguities that currently shroud these terms. The Midwest ISO suggests that the Commission adopt the following definitions for these terms:

'Expected levels' should be defined as Baseline, as defined by the NAESB standards recently adopted by reference by the Commission.

'price signals' should be defined as the full set of market prices established by RTO market activities or through bilateral markets.

'market prices' should be defined as market clearing prices like those identified above (*e.g.*, Day-Ahead LMPs) established in RTO tariffs.

VI. CONCLUSION

The Midwest ISO respectfully submits these comments on the subject NOPR to assist the Commission in further refining its approach to demand response compensation.

Respectfully submitted,

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May 13, 2010

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UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. RM10-17-000

DEMAND RESPONSE COMPENSATION IN ORGANIZED WHOLESALE ENERGY MARKETS

Docket No. EL09-68-000

PJM INTERCONNECTION, L.L.C.

[May 13, 2010]

COMMENTS OF WAL-MART STORES, INC. TO THE NOTICE OF PROPOSED RULEMAKING ON DEMAND RESPONSE COMPENSATION IN ORGANIZED WHOLESALE ENERGY MARKETS

On March 18, 2010, the Federal Energy Regulatory Commission ("FERC" or "Commission") issued a Notice of Proposed Rulemaking that proposes an approach for compensating demand response resources in order to improve the competitiveness of organized wholesale energy markets and ensure just and reasonable wholesale rates.[1] Wal-Mart Stores, Inc.

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[1] *Demand Response Compensation in Organized Wholesale Energy Markets*, Notice of Proposed Rulemaking, 130 FERC ¶ 61,213, at P 1 (2010) ("DR NOPR").

("Walmart") supports the Commission's proposals to eliminate barriers to the full and non-discriminatory participation of demand response resources in organized wholesale markets and views this DR NOPR as another positive step in the effort. In response to the DR NOPR, Walmart respectfully submits the following comments.

Walmart has participated actively in many demand response programs, including directly through aggregators as a resource in the wholesale market administered by the Independent System Operators ("ISO")/ Regional Transmission Organizations ("RTO") and indirectly at the retail level, through programs where regulated distribution utilities manage consumer demand response programs. Walmart also recently participated in a successful test pilot program directly with the California Independent System Operator ("CAISO"). Walmart strongly supports the Commission's proposal to compensate demand response resources by paying the wholesale market price (*i.e.*, the locational marginal price ("LMP")) for energy for such reductions.[2] Walmart submits that: (1) there is a need to establish a just compensation mechanism for demand response services because increased participation has significant benefits for the wholesale organized markets and current compensation methods have not resulted in optimal participation by demand response providers; and (2) full LMP pricing is a just and

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[2] DR NOPR at P 11.

reasonable measure of compensation for demand response resources.

I. Walmart's Continued Investment in Demand Response Resources Depends on Comparable Compensation for Its Services.

Walmart is an international retailer serving over 4,300 locations across the U.S. and over 4,100 locations internationally. Walmart has been an active participant in many demand response programs, including programs offered through utilities, cooperatives, ISO/RTOs through aggregators, and as noted above, an independent direct test pilot for demand response capability with the CAISO. Walmart has participated in as many as 17 different demand response programs at approximately 1,300 locations in 23 states.[3]

Walmart expects to continue its investment in demand response resources and direct participation in the wholesale markets administered by the ISO/RTOs as long as such participation is both economically feasible and rational. Fair compensation for demand reduction resources, which should be provided in the form of full LMP pricing, at a minimum, will help ren-

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[3] *See* Comments and Protests of Demand Response Supporters and Answer of Demand Response Supporters in PJM Interconnection, L.L.C., Docket No. EL09-68-000 (Wal-Mart Stores East, L.P. is a member of the referenced Demand Response Supporters); *See also* Comments of the National Energy Marketers Association, Docket No. AD09-10-000 (Apr. 6, 2010).

der demand response participation more economically feasible for Walmart and other customers.

II. Demand Response Resources in Organized Wholesale Markets Must Be Compensated Fairly

In the DR NOPR, the Commission seeks comments on the need to compensate demand response acting as a resource in organized wholesale energy markets. The Commission also seeks comments on whether current compensation in these markets is adequately procuring demand response. Indeed, the DR NOPR describes that demand response providers collectively play a small role in wholesale markets and that the Commission is concerned that "some existing, inadequate compensation structures have hindered the development and use of demand response."[4]

Demand response resources should be compensated for their consumption reduction services because such reductions provide significant benefits to the organized wholesale energy markets. Adequate compensation in the ISO/RTO programs, moreover, is particularly important because participation in these programs preserves the right of consumers to choose among beneficial demand response programs and allows consumers to retain "environmental attribute" benefits that result now and in the future from ownership of the demand response resource. Lastly, fair compensation is required to encourage further customer participation and investment in demand re-

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[4] DR NOPR at P 9.

sponse resources in order to achieve significant demand response participation.

A. The Benefits of Demand Response in Organized Wholesale Energy Markets

As identified in the DR NOPR, there are numerous benefits provided by demand response in the organized wholesale energy markets.[5] These benefits include lower energy prices for all consumers as a result of bidding demand response directly into the wholesale market, which reflects lower demand, and by reducing the need for the dispatch of higher-priced generation during high-price periods. In addition, demand response can mitigate generation market power, by providing an alternate resolution to peak demand other than higher supplier prices. Moreover, as the Commission acknowledges, demand response can be particularly beneficial during times of unexpected loss in generation, which is a valuable and unique service.[6]

Demand response also helps reduce transmission congestion, which allows for better use of the existing transmission and generation investment. Other benefits of demand response include reduction of greenhouse gas emissions by reducing the need for energy from existing fossil-fueled generation plants and future peaker generation plants.

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[5] DR NOPR at P 4.

[6] *Id.*

B. The Need for Fair Compensation in the ISO/RTO Demand Response Programs

Demand response participants must be fairly compensated in order to preserve the customer's choice between direct participation as a resource in the ISO/RTO markets and participation at the retail level in distribution utility-run programs.

Participation in demand response offered by distribution utilities does not always ensure the same rights and benefits as participation in the ISO/RTO markets and can add unneeded bureaucracy and unnecessary increases to the customer's energy costs. For example, customers participating in distribution utility programs must sometimes cede some level of control of the resource and could feasibly forfeit possible economic benefits to the utility as a "middle man," including the ownership of environmental benefits. This tension is reflected in the current struggle of ownership of environmental benefits. This tension is reflected in the current struggle of ownership rights of benefits and attributes specific to renewable projects and energy efficiency. Customers providing demand response services directly to the wholesale markets, on the other hand, retain control of the resource and its economic benefits including their rights to environmental attributes, now and in the future, associated with the customer's participation as owner of the demand response measures.

The existence of a viable ISO/RTO demand response program preserves critical customers choices

that will govern how customers will deploy capital for demand response measure. Walmart has appreciated the ability to choose to contribute its demand response and other services to the ISO/RTO markets. The Commission must ensure just compensation in the ISO/RTO markets because it preserves such a necessary customer choice and an alternative to distribution utility demand response programs.

C. Current Compensation Does Dot Adequately Procure Demand Response Resources

As the Commission notes, despite the benefits of demand response, the wholesale markets consist of a relatively small portion of demand response resources.[7] Customers are more likely to invest in or dedicate additional resources to wholesale demand response measures if the ISO/RTOs establish a transparent, consistent, and fair compensation structure. For example, the DR NOPR correlates a decrease in settle demand reductions to a decrease in demand response compensation in the PJM markets in January 2008.[8] The existing levels of compensation, however, fail to reflect the marginal value of demand response resources to ISO/RTO energy markets.[9] As a result,

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[7] DR NOPR at P 9.

[8] DR NOPR at P 10.

[9] The Commission observes that it "has previously accepted a variety of ISO and RTO proposals for compensation." As the Commission gained experience with these programs, however, the Commission states that it is "concerned that the current compensation levels appear to have become unjust and unreasonable. Pro-

the Commission is rightly concerned, and Walmart agrees that current wholesale compensation levels for demand response are inadequate, not comparable to generation, and therefore ultimately fail to increase further participation by demand response resources.

Morever, business customers such as Walmart are willing to deploy demand response resources in certain wholesale markets, making significant investments and business sacrifices to do so. However, in order for customers to make these investments, the customer must receive not only adequate compensation for demand response services provided but also comparable, consistent and transparent compensation to ensure such customers receive a reasonable return on their investments, which then can be reinvested in demand-related resources. For example, Walmart has used the compensation that it receives for its demand reduction and curtailment services, particularly in certain ISO/RTO programs, to deploy additional demand resources and install advanced metering systems at many of its facilities. Indeed, Walmart has installed over 1,300 advanced metering systems across the country.

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viders may submit price and quantity bids into the organized wholesale energy markets and the market clears at the marginal resource yet they fail to compensate demand response at levels that reflect the marginal value of the resource being used by the RTO or ISO to balance supply and demand." DR NOPR at P 13.

Compensation at full LMP prices is an appropriate market-based compensation for demand response resource services, including an adequate return on investment, and therefore will encourage increased additional investment in demand response resources.

III. Full LMP Pricing Is a Just and Reasonable Compensation Mechanism

The Commission seeks comments on alternative approaches to compensating demand response resources participating in organized wholesale energy markets in comparison to full LMP pricing, and in particular: (1) whether LMP pricing is the best method of compensation; (2) whether a reduction in consumption is comparable to an increase in electricity production for purposes of balancing supply and demand; (3) whether paying LMP for demand response is comparable compensation paid to generation; and (4) whether LMP pricing should apply to all hours and across all ISO/RTOs.[10]

A. Full LMP Fairly Compensates Demand Response Resources

The DR NOPR, which requires ISO/RTOs to pay full LMP to demand response resources for demand reductions, provides fair compensation.[11] The DR NOPR correctly notes that such compensation reflects the marginal value of demand response resources to

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[10] DR NOPR at P 20.

[11] DR NOPR at P 11.

each RTO and ISO. Such transparent pricing also allows consumers to compare more accurately the services and costs offered by potential demand response aggregators.

Importantly, full LMP pricing is the best compensation mechanism for demand response participants because LMP reflects a transparent price of energy that sends clear signals to demand response participants considering further investments in demand response measures. LMP pricing further allows the benefits of participation in demand response to flow directly to the customers who choose to expend capital and deploy demand response resources. These benefits reflect that LMP compensation puts all resources —demand and supply—on a comparable level. This helps ensure that the pricing structure does not unduly discriminate against demand response resources in contradiction to Commission policy.[12]

Reduction in consumption is comparable to an increase in electricity production for purposes of balancing supply and demand in the RTO/ISO markets. Both load reduction through demand response and increased operation of power plants ensure reliability and adequate power to consumers when needed and, therefore, load and generation resources must be

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[12] *See Wisc. Pub. Power, Inc. v. FERC*, 439 F.3d 239, 246 (D.C. Cir. 2007) (FERC policy is to promote competition and eliminate barriers to competition in the wholesale market, which constitute undue discrimination).

treated comparably. As the DR NOPR correctly surmises, in balancing supply and demand, one megawatt reduction in demand is equivalent to one megawatt increase in energy.[13] The ISO/RTO can avoid dispatching generation supply with higher price bids (either through generation or demand response) by accepting a lower bid to either reduce consumption or increase generation. Both options allow the ISO/RTOs to maintain a reliable electric system and should be compensated comparably. Any compensation mechanism, other than full LMP compensation, would unjustly and unreasonably discriminate against demand-side resources in favor of supply resources.

The DR NOPR also seeks comments on whether paying full LMP to demand response resources is comparable compensation, or is more or less than comparable compensation, paid to generation in the ISO/RTO energy markets.[14] For example, in its recent demand response proceedings, PJM asserted that the appropriate compensation is full LMP prices *minus* the generation portion of the consumer's retail rates because the generation component of retail rates is a substitute for LMP.[15] This PJM pricing scheme is unjust and unreasonable because it discriminates against demand-side resources providing services to the wholesale market and, in turn, forces demand

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[13] DR NOPR at P 15.

[14] DR NOPR at P 20.

[15] DR NOPR at P 8.

resources, such as a customer providing a service of curtailment, to pay for a retail service—generation supply to consumers—that it does not use during its demand reductions.

In other words, when a retail customer such as Walmart reduces its energy demand and provides that service to the wholesale market, it does not cause wholesale generation costs. Instead, Walmart should be compensated fully for the reduction services it provides to the wholesale market. Moreover, demand response resources provide services that are free of greenhouse gas emissions in contrast to other generation resources. Demand response resources should be compensated, at a minimum, at full LMP because the services they provide tend to reduce greenhouse gas emissions (and thus potential greenhouse gas emission penalties passed on to consumers) at much lower costs to consumers.

Lastly, requiring all ISO/RTOs to pay full LMP to demand response providers for all hours is the best mechanism for determining just compensation because it will promote a simple compensation system and improve administrative efficiency. The Commission should exercise its proper jurisdiction and implement a compensation structure, consistent and compatible for all ISO/RTO markets. This structure allows a consistent and fair method of compensation across markets and resources—supply and demand alike—which reduces additional barriers to demand response participation.

E. Dynamic Retail Pricing Does Not Drive Significant Capital Investment in ISO/RTO Demand Response

Paying full LMP is just and reasonable because it represents the proper value for demand response investment in wholesale markets and will attract and encourage greater demand response participation. Commissioner Moeller, however, comments in his dissent to the DR NOPR that the primary barrier to increased demand response is the disconnect between retail and wholesale prices and that the remedy resides at the retail level where there is a lack of dynamic pricing.[16] Walmart respectfully disagrees.

Dynamic retail pricing educates customers and can send customers much needed transparent pricing for the cost of energy delivered through the utility distribution system. It also allows retail customers to receive economic signals and pay for electricity based on revised prices throughout the day, during expensive peak and inexpensive off-peak periods. Dynamic retail price signals also can encourage customers to seek out retail electricity marketers with different pricing alternatives including more stable pricing than a utility electricity supply tariff that could fluctuate dynamically. Customers can also install energy efficiency

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[16] Demand Response Compensation in Organized Wholesale Energy Markets, Docket No. RM10-17-000; Moeller, Commissioner, *concurring in part* and *dissenting in part* (Mar. 18, 2010).

measures to reduce retail usage and thus overall retail charges.[17]

Dynamic retail pricing, however, is a longer-term solution, as customers incrementally optimize their operation as they acclimate to move to granular pricing. RTO/ISO demand response programs, however, address an immediate need to balance supply and demand, as demand response providers participate in the wholesale marketplace in a similar manner to generation resources. Therefore, demand response providers should be compensated accordingly both for their services provided and the expected return on investment. Dynamic retail pricing, retail shopping opportunities and the potential for retail energy efficiency measures are no substitute for adequate wholesale demand response compensation and the deployment of demand response measures akin to a generation resource.

The Commission should oppose any efforts to equate or combine energy efficiency and demand response programs. These two programs are fundamentally different and pose different considerations.

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[17] Even in this regard, dynamic retail pricing often can be insufficient to provide incentives to shop or install energy efficiency measures without further changes to the utility's cost allocation and retail rate structure. In order to achieve appropriate dynamic retail pricing, utilities also should consider improvements to their retail rate structure and ensure costs to serve retail customers are appropriately allocated to the consumer along cost causation principles.

Energy efficiency essentially is a passive usage reduction technology while demand response programs usually require active participation. Many energy efficiency programs are developed by utilities, which are funded by retail ratepayers through a rate or surcharge or through taxpayer dollars. The funding for these energy efficiency programs also can include: (1) additional utility cost recovery for perceived revenue reduction associated with reduced energy consumption; and (2) the provision of rebates to the customers or incentives to the utility for energy efficiency customer participation. This represents a significant layer of bureaucracy and subsidies not found when consumers directly participate in the ISO/RTO demand response markets.

Combining demand response with energy efficiency likely could subject already successful ISO/RTO demand response programs to unnecessary additional layers of local utility rate proceedings, administration, volume and revenue calculations and incumbent retail cost recovery efforts that are currently part of energy efficiency programs. This "combining" could create additional costs, administration and barriers to demand response participation. Keeping energy efficiency and demand response separate helps preserve customer choice through participation in viable ISO/RTO demand response programs, instead of creating another monopoly for utilities over their customers' demand response options. This would burden consumers with unnecessary additional costs and process,

which likely will act as a barrier to the expansion of demand response for the benefit of consumers.[18]

As said earlier in Walmart's comments, enhancing opportunities for customers to provide demand response services directly to the wholesale markets maintains multiple benefits to consumers, including the ability of the customer to decide which demand response programs best serves the customer's needs.

IV. Conclusion

Walmart appreciates the opportunity to submit these comments. Walmart supports the DR NOPR's proposal to pay, at a minimum, full LMP prices to demand response providers. Demand response provides significant benefits to organized wholesale energy markets. A just and reasonable compensation method, applied consistently by all ISO/RTOs, will reduce an unnecessary barrier to demand response participation and help promote greater participation. Paying full LMP prices, as proposed by the DR NOPR, is a just and reasonable compensation method that will help achieve greater demand response participation by adequately compensating consumers for

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[18] *See* Comments of Wal-Mart Stores, Inc. on the Draft National Action Plan on Demand Response, Docket No. AD09-10-000, at 7 (2010).

their active participation investments in demand response resources.

Respectfully submitted,

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Dated: May 13, 2010

UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. RM10-17-000 and EL09-68-000

Demand Response Compensation in Organized Wholesale Energy Markets

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May 13, 2010

COMMENTS OF POTOMAC ECONOMICS, LTD.

Potomac Economics, Ltd. ("Potomac Economics") submits these comments in response to the Federal Energy Regulatory Commission's ("FERC" or "Commission") March 18, 2010 Notice of Proposed Rulemaking ("Notice" or "NOPR") in the above captioned proceeding. Potomac Economics serves as the External Market Monitor or the Independent Market Monitor ("IMM") for the Midwest Independent Transmission System Operator ("Midwest ISO"), the New York ISO ("NYISO"), ISO New England, and ERCOT.

I. Communications

The name, title and address of the person to whom to whom communications concerning this filing are to be addressed is as follows:

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II. Background

In this proceeding, the Commission has proposed an approach to compensate demand response resources with a view to enhancing the competitiveness of wholesale electricity markets. In its NOPR, the Commission emphasized that to ensure that wholesale prices in ISOs and RTOs remain just and reasonable, "each Commission-approved ISO and RTO that has a tariff provision providing for participation of demand response resources in its energy market must pay demand response resources, in all hours, the market price for energy, i.e., full LMP, for demand reductions made in response to price signals."

While the NOPR explicitly states it is the Commission's belief that the market will ultimately determine the appropriate mix of generation and demand response ("DR") resources, it is also states that it is the Commission's belief that an 'appropriate' level of compensation for demand response resources is essential to enable the participation of DR resources in wholesale energy markets. In that vein, the NOPR postulates that the appropriate level of compensation is the full LMP, "because that payment reflects the marginal effect of each demand response resource in the hour,

just as the LMP reflects the marginal effect of generation resources in each hour" These comments provide our evaluation of the Commission's proposal based solely on of economic efficiency.

III. Comments

Demand Response is comprised of actions that can reduce consumption during certain hours from normal consumption patterns. Demand participation in the market is beneficial in many ways. It contributes to reliability in the short-term, resource adequacy in the long-term, reduces price volatility and other market costs, and mitigates supplier market power. Additionally, price-responsive demand has the potential to produce sizable savings by enhancing wholesale market efficiency. Even modest reductions in consumption by end-users during high-price periods can significantly reduce the costs of committing and dispatching generation to satisfy the needs of the system. If the value of foregone consumption is substantial lower than the cost of the displaced generation, this transaction will result in meaningful efficiency benefits. Additionally, if the DR resource sets the wholesale price at the marginal value of its foregone consumption, it will send an efficient price signal to others in the market that should improve their short-term and long-term decisions.

For these reasons, Potomac Economics has long supported the development and integration of demand-response resources in the wholesale electricity markets. Such development will be efficient and benefi-

cial if undue barriers are eliminated and the market rules provide efficient incentives to existing and prospective new DR resources. The Commission recognized this in issuing the NOPR and we applaud this step to gather feedback on these important issues.

A. Net Settlements with DR Resources, LSEs and Generators

At the outset, we believe that it is impossible to evaluate any settlement or payment proposal unless all settlements associated with the marginal decision to consume (or produce in the case of a generator) are considered together. The unique aspect of most demand response resources is that the decision to consume or curtail simultaneously affects their settlements with their load serving entity ("LSE") and Independent System Operator ("ISO"). Hence, it is impossible to evaluate the Commission's proposals in the NOPR regarding the settlements with the ISO unless assumptions regarding the DR's settlements with the LSE are made explicit. We refer to these settlements together as the DR's "net settlement" It is the net settlements with the DR participant and the LSE that determine whether an ISO's market rules and settlement are efficient.

As we describe below, Potomac Economics supports the Commission's mandate which requiring that ISOs pay DR resources the full LMP for demand reductions as long as certain conditions hold regarding how the ISO settles with the LSE, and how the DR resource settles with the LSE.

To evaluate the impact of alternative settlement rules for DR resources on efficiency, we create some illustrative examples that show the ISO's settlements with generators, DR resources and load serving entities. To get a full understanding of each participant's incentives and how the outcomes differ, it is important to define the marginal costs and benefits of the decision to produce, consume (or not to consume) by each participant.

- For a generating resource, its marginal cost is the cost of producing additional electricity, which is reflected in the generators' energy offers in a competitive market.
- For a DR resource, its marginal cost of reducing demand is equal to the marginal value of its consumption that will be foregone. Therefore, in cases where the DR participant consumes, we show their assumed marginal value of consumption. In cases where the DR participant *curtails*, the marginal value of consumption drops to zero (since they no longer capture that value when they curtail).

The total cost or surplus, therefore, is the sum of the applicable settlements and the participants' marginal cost or benefit. For example, generation resources incur the marginal cost of production in order to produce an incremental unit of energy and are paid the LMP. A supplier's surplus would be the difference between the two. Likewise, the surplus for the demand resource that *consumes* would be the differ-

ence between its marginal value of consumption and the retail price it pays its LSE for the power.

To evaluate settlement alternatives for DR resources, we use a simplified example that shows the settlements, marginal values/costs, and total costs or surplus for each participant. These examples should make the costs and incentives of each alternative clear.

B. Base Case Settlements

We first show a 'Base Case' scenario that illustrates settlements for all entities in normal case where the demand consumes and the generator runs to produce the energy. In these examples, we assume that the generator and DR resource have identical marginal cost and marginal value of consumption equal to $200/MWh. We assume that the DR resources retail rate equals $80/MWh. The settlements are shown below along with the final net cost or surplus for each entity.

Base Case Scenario (Demand Response Resource Consumes)

	Generator	LSE	DR Resource
Cash InFlow	$200	$80	$0
(Cash Outflow)	$0	($200)	($80)
Marginal Value (Marginal Cost)	($200)	$0	$200
Net Cost or Surplus	**$0**	**($120)**	**$120**

In this scenario, the generator breaks even because its marginal cost and LMP-based payment are the same. The DR resource enjoys a $120/MWh surplus because its value of consumption exceeds its $80/MWh retail rate. This surplus is the value of the retail cus-

tomer's property right in that hour. The retail customer has the right to purchase energy at $80/MWh, which it is exercising in this example. As we will illustrate below, the function of an efficient DR program is to allow the retail customer to monetize this property right (i.e., re-sell the power at the wholesale price that it purchased at the retail price)

Likewise, the LSE incurs a loss because its wholesale cost of $200/MWh is less than the $80/MWh it receives from the retail customer. This is not a problem because the retail rates are generally designed, on average, to cover the wholesale costs of purchased power. In the examples that follow, we compare the net settlements of each alternative to the base case settlements to highlight the incremental changes.

C. Comparison of Alternative Settlements for Demand Response

The next two cases compare two basic alternatives, one in which the DR resource must buy the energy at the retail price that it is offering to sell back into the real-time wholesale market by curtailing, and the other where it is not required to buy the energy that it is selling in the wholesale market.

While both alternatives show that the DR resource is paid the LMP, they differ in the assumptions regarding the DR resource's obligation to pay the LSE for the power being curtailed. The NOPR does not address the settlements between the DR resource (the

retail customer) and the LSE serving the retail customer.

1. Alternative I: Pay LMP with no Retail Settlement

The settlements under the first alternative which simply comprises paying a DR resource the LMP are shown below. The first table shows the settlements under a scenario where the DR resource curtails its consumption and the second table shows the net change in settlements as compared to the Base Case.

Alternative I: Pay LMP with no Retail Settlement

	Net Settlements			Change in Settlements from Base Case		
	Generation	LSE	DR Resource	Generation	LSE	DR Resource
Cash In/Flow	$0	$0	$200	($200)	($80)	$200
Cash Out/Flow	$0	($200)	$0	$0	$0	$80
Marginal Value (Marginal Cost)	$0	$0	$0	$200	$0	($200)
Net Cost or Surplus	$0	($200)	$200	$0	($80)	$80

This table shows that the LSE's net cost has grown by $80/MWh, while the DR resource's settlement has improved by $80/MWh. Economically, however, nothing has changed. A $200/MWh demand resource has displaced a $200/MWh generating resource. This produces no savings to the system, yet the net payments to all resources (DR and generation) have risen by $80. Interestingly, the DR resource itself should be indifferent to curtailing in this case since the cost of serving the demand (the LMP) exactly equals the demand's value of consumption. However, the DR resource is not indifferent.

The reason the DR resource is not indifferent is that it is no longer simply monetizing its property

right to purchase power at $80/MWh. We are now allowing the DR resource to sell energy in the wholesale market that it is not required to purchase at the retail rate. Hence, one can clearly see in this case that the DR resource is receiving a subsidy to curtail equal to the retail rate.

This will manifest itself in potentially significant economic inefficiencies. In this case, for example, the DR resource would be willing to curtail in any hour that the price is above $120/MWh ($200 marginal value of consumption minus the $80 curtailment subsidy). This would cause a DR resource with a true marginal value of $200/MWh to displace lower cost generating resources. If it were to displace a $130/MWh generator, for example, the system would incur an efficiency loss equal to $70/MW per hour.

2. Alternative II: Pay the LMP with Retail Settlement

The settlements for the second alternative are shown in the table below. Similar to the previous example, the left columns show each of the settlements in this alternative where the ISO continues to bill the LSE for the curtailed load (we refer to this as "reconstituted load") and the LSE continues to bill the DR resource for the reconstituted load at the retail rate of $80/MWh.

Alternative II: Pay LMP with Retail Settlement

	Net Settlements			Change in Settlements from Base Case		
	Generator	LSE	DR Resource	Generator	LSE	DR Resource
Cash bill/rev	$0	$80	$200	($200)	$0	$200
Cash curtailment	$0	($200)	($80)	$0	$0	$0
Marginal Value/Marginal Cost	$0	$0	$0	$200	$0	($200)
Net Cost or Surplus	**$0**	**($120)**	**$120**	**$0**	**$0**	**$0**

In this example, the net costs and surpluses remain unchanged from the base case. This is logical since the total costs to the system are unchanged and both the generator and the DR resource are indifferent to running, consuming or curtailing. This indifference is because their respective marginal cost or marginal value of consumption are exactly equal to the LMP. In this alternative, the subsidy has been eliminated and the LSE is also indifferent—there is no incremental uplift cost the LSE would bear to fund the subsidy.

3. Alternative II when DR Resource is Inframarginal

In the final example, we show the true value of the demand response program. In this case, the LMP has risen to $500/MWh, but the DR resource's value of consumption is only $200/MWh. By curtailing, it can achieve efficiency savings of $300/MWh.

Alternative II when the DR Resource is Inframarginal

	Net Settlements			Change in Settlements from Base Case		
	Generator	LSE	DR Resource	Generator	LSE	DR Resource
Cash bill/rev	$0	$80	$500	($500)	$0	$500
Cash Curtailment	$0	($500)	($80)	$0	$0	$0
Marginal Value/Marginal Cost	$0	$0	$0	$500	$0	($200)
Net Cost or Surplus	**$0**	**($420)**	**$420**	**$0**	**$0**	**$300**

The table shows that the DR resource is now able to monetize its property right to buy power at $80 and sell it at the LMP of $500/MWh. Without the DR program, the best it can do is to consume and receive the $120/MWh surplus ($200-$80). Hence, it has captured the additional $300/MWh in benefits that it is providing to the system, notwithstanding that it must continue to pay the retail rate.

D. Allowing Flexibility in Dealing with Differing Retail Regulation

The examples above illustrate that economic efficiency is served by continuing to settle with the LSE and the retail customer on the reconstituted load. However, some state retail regulatory structures may not accommodate settlements with the retail customers that would include charges for reconstituted load. Therefore, FERC may need to be flexible in evaluating ISO DR programs. Where state regulation cannot accommodate the retail settlements described above, the same outcome can be achieved by subtracting the applicable retail rate from the wholesale payment made to the DR resource. Some have proposed subtracting only the generation portion of the retail rate, however parity with the example above would require that the entire retail rate be removed.

IV. Conclusion

In conclusion, Potomac Economics believes that DR resources play an important role in increasing competitiveness and efficiency of wholesale energy. Poto-

mac Economics has long been a supporter of the integration of DR resources in wholesale energy markets and supports the Commission's view on adequately compensating DR resources while maximizing overall efficiency.

In this response to the Commission's proposal, we have illustrated the importance of explicitly recognizing the retail settlements when structuring an efficient payment at the wholesale level for DR resources. We believe that recognition of differing retail rate structures may require flexibility by the Commission, rather than a one-size-fits-all approach to structuring DR settlement rules in each ISO market. Hence, we would encourage the Commission to establish guidelines for the ISOs that would be premised on maximizing economic efficiency, rather than requiring a specific DR payment scheme.

WHEREFORE, for the foregoing reasons, Potomac Economics respectfully requests that the Commission consider these comments.

Respectfully submitted,

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May 13, 2010

UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. RM10-17-000

DEMAND RESPONSE COMPENSATION IN ORGANIZED
WHOLESALE ENERGY MARKETS

May, 13, 2010

COMMENTS OF THE INDEPENDENT MARKET MONITOR FOR PJM

Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor for PJM[1] ("Market Monitor"), submits these comments in response to the notice of proposed rulemaking ("NOPR") issued in this proceeding on March 18, 2010.

The Market Monitor appreciates the Commission's ongoing commitment to the development of the demand side of wholesale power markets. The Market Monitor has consistently cited the need to address the underdevelopment of the demand side of the organized wholesale markets administered by PJM Interconnection, L.L.C. by

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[1] PJM Interconnection, L.L.C., a FERC approved Regional Transmission Organization. Capitalized terms used herein and not otherwise defined have the meaning used in the PJM Open Access Transmission Tariff ("OATT").

promoting the legal, regulatory, administrative and technical infrastructure needed to provide appropriate price signals, remove barriers to demand side entry and ensure measurement and verification.[2]

The Commission should, to the extent that it can, provide incentives for the development of this infrastructure and lead the effort to coordinate the development of demand side across and within regions.

The NOPR proposes a policy that would compensate participants in economic demand response programs in the organized wholesale markets at the prevailing price for wholesale electric power ("locational marginal price" or "LMP"). The Market Monitor agrees that the LMP is the " marginal cost of the last unit necessary to efficiently balance supply and demand" and is the correct price signal to generation and load.[3]

However, the result of the proposed implementation of this policy would be that demand side participants would receive the LMP plus the avoided cost of purchas-

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[2] *See, e.g.*, 2009 State of the Market Report for PJM at 103 ("Markets require both a supply side and a demand side to function effectively. The demand side of wholesale electricity markets is underdeveloped. Wholesale power markets will be more efficient when the demand side of the electricity market becomes fully functional."); Market Monitor, "Barriers to Demand Response in PJM," filed Docket No. ER09-1063, et al. (July 1, 2009) ("Barriers Report").

[3] NOPR at P 14.

ing power. For customers already paying retail rates equal to the LMP, such compensation would be twice LMP. This proposal is inconsistent with fundamental economics and, if adopted by the Commission would over compensate participants in economic load response programs, negatively affect the efficient operation of the energy markets and provide no offsetting social benefit.

I. COMMENTS

The NOPR requests comments (at PP 20–22) on a number of issues pertaining to the efficient and effective compensation for demand side resources ("DSR") and whether uniform treatment of such resources is appropriate. The Market Monitor specifically addresses below the first two topics of inquiry.

A. Whether there is a need to compensate demand response acting as a resource in organized wholesale energy markets.

The assertion that customers who agree to reduce energy use during an hour should receive full LMP is correct. The assertion that such customers require a payment under the PJM DR programs equal to full LMP is not correct. The difference between these two assertions has been the source of much confusion. The confusion turns, in part, on what is meant by "compensation."

In the energy market, as in all markets, sellers sell products and buyers buy products. These are two distinct activities and are not comparable. When a seller sells a product, the seller receives the market price.

When a buyer buys a product, the buyer pays the market price. If a buyer does not buy a product, the buyer avoids paying the market price. The buyer is not compensated in any other way. The interaction of sellers selling and buyers buying results in a market clearing price, which defines the market value of the product. The only reason that this basic market dynamic does no work in wholesale power markets is that retail customers do not pay the market price on a real time basis. If customers paid the market price, there would be no need for demand side programs and no need for any discussion of compensation.

One of the central preconditions for complete markets does not yet exist for power markets. Customers, as a general matter, do not know and do not pay the market price of wholesale power. Customers pay a retail price that frequently bears only an attenuated relationship to the real time hourly LMP This is the fundamental barrier to the development of the demand side of wholesale power markets. The market price for wholesale power is the LMP in organized markets and more specifically the price that reflects actual supply and demand conditions at the specific location and time that power is purchased. This barrier has led to the creation of demand side "programs" designed to work around the absence of price information rather than to the direct provision of wholesale prices to customers.

A fully functional demand side of the electricity market means that end use customers or their designated in-

termediaries will have the ability to see real time energy price signals in real time, will have the ability to react to real time prices in real time, and will have the ability to receive the direct benefits or costs of changes in real time energy use. When these conditions are met, customers can and will make decisions about how much power to use, including investments in demand side management technologies, based on their own evaluations of the tradeoffs among the price of power, the value of particular activities and the costs of those technologies.

Today, most end use customers do not face the market price of energy, that is, the locational marginal price of energy (LMP). This results in a market failure because when customers do not know the market price and do not pay the market price, the behavior of those customers is inconsistent with the market value of electricity. The transition to a more functional demand side requires that the default energy price for all customers be the day ahead or real time hourly LMP When the default price for customers is the hourly locational price of energy, customers will have the ability to enter into contracts with intermediaries for fixed price contracts under which the intermediaries take the risks of volatile prices. The intermediaries would then have the incentive to respond to price signals and to incent the customers to respond to price signals.

The most basic barrier to a fully functional demand side of the market is that not all customers are exposed to the actual incremental cost of energy.

The assertion that demand side participants should be paid full LMP, regardless of their retail tariff rate, because the current approach of paying LMP minus G represents an intervention into retail rate design, cannot be correct. The entire demand side program exists only because of the disconnect between wholesale and retail rates. The assertion that the program design should not account for the details of retail rate design leads to the conclusion that there should be no demand side program at all.

Demand side programs are generally designed to work around this market failure rather than to address it directly. PJM's Economic Load Response Program is designed to work around this market failure by attempting to replicate the price signal to customers that would exist if customers were exposed to the real time wholesale price of energy and by providing settlement services to facilitate the participation of third party Curtailment Service Providers (CSPs) in the market.[4]

The term "demand side resource" means the willingness of customers to respond to prices by reducing usage when the price of power exceeds the value to the customer. This willingness can take the form of an agreement to reduce usage when the price is above a certain

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[4] The design of PJM's Load Management (LM) Program in the RPM market also attempts to replicate the price signal to customers that would exist if customers were exposed to the locational market price of capacity.

level or an agreement to reduce usage whenever the customer wants to respond to price.

PJM's demand side programs are designed to address this barrier to the full development of a demand side of the wholesale power markets. Ultimately, all of the barriers to demand side participation must be addressed directly. The integration of demand resources into PJM markets through PJM's demand side programs should be understood as one relatively small part of the transition to a fully functional demand side for PJM markets. The complete transition to a fully functional demand side will require explicit agreement and coordination among the Commission, state public utility commissions and RTOs/ISOs.

When customers directly face market prices and have the ability to respond to such prices and to directly receive the benefits of their choices, there will be only a limited need for demand side programs. There will be a need for clear market rules governing the participation of demand side resources in energy, capacity and ancillary services markets, but there will be a sharply reduced need for elaborate measurement and verification programs. Customers will choose to consume or not consume energy based on the price. The metered usage and the bill will reflect that choice, and the assessment of that choice will belong to the customer. In the capacity market, a fully functional demand side will require that customers who wish to avoid paying for capacity provide an enforceable commitment to be interruptible by the RTO above a de-

fined level of capacity, based on a clear and transparent market signal.

The assertion that the reduction of market prices is a social benefit is not correct. In a market with no externalities, the market price reflects the decisions of sellers and buyers and represents the efficient outcome. There is no reason to provide an incentive to reduce the market price below this efficient outcome. The result would be to provide an incentive for those who use energy, e.g. productive businesses in other markets, to produce less of their product and to use fewer workers. If there are relevant externalities associated with the production of electricity, these should be incorporated in the costs of generating power and thus reflected in the price of power.

B. Whether current compensation for demand response providers acting as a resource in the organized wholesale energy markets is adequately procuring demand response.

The NOPR cites to the Market Monitor's findings of recent declines in participation by PJM loads in PJM's Economic Load Response Program.[5,6] The State of the

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[5] NOPR at P 10 ("Indeed, there are indications that demand response resources react correspondingly to increases or decreases in payment. PJM provides a case study on this point. It first implemented its Economic Load Response Program (Economic Program) providing for demand response compensation in June 2002.[footnote omitted] Several years later, starting in January 2008, when PJM reduced its compensation for demand response, settled demand reductions began decreasing from previous years.[footnote omitted] Specifically, PJM's Market Monitor noted

that, from 2007 to 2008, following the decrease in compensation, settled demand reductions decreased by 36.8 percent, from 714,200 MWh to 458,300 MWh, and the decline has continued at least through March 2009.[footnote omitted] Although the Commission had rejected a request to prevent the compensation decrease from occurring as per the terms of PJM's then-existing tariff, the Commission encouraged PJM and its stakeholders to continue analyzing the effectiveness of PJM's demand response program with the decreased payments for demand response.[footnote omitted] Based upon our own review, the Commission is now concerned that evidence of demand reductions in PJM, and inadequate demand response participation, now and in the future, may be the result of compensation that is no longer just and reasonable, because, as detailed below, the existing and varying levels of compensation generally fail to reflect the marginal value of demand response resources to ISO and RTO energy markets.").

[6] NOPR, Commissioner Moeller's Dissent ("While the majority claims that it is "concerned that compensation for demand response in PJM and other RTO and ISO markets may no longer be just and reasonable", the NOPR lacks a thorough discussion of the evidence that they relied upon to substantiate their concerns.[footnote no. 6: In support of the conclusion that compensation may no longer be just and reasonable, the preamble provides an example involving PJM's Economic Load Response Program and the drop of settled demand reductions experienced after the subsidy payments expired per the terms of PJM's tariff. NOPR at P 10. While the cited level of reduction is a fact, the PJM market monitor stated that "[w]hile the removal of the incentive program, effective November 2007, may have reduced participation, the exact role of the elimination of the incentive program is not known because there were changes to other key factors which directly impact participation." Citing Monitoring Analytics, Barriers to Demand Side Response in PJM, at 22 (July 1, 2009). More recently, the PJM market monitor recognized that between 2008 and 2009, "[t]here were many factors contributing to the lower levels of participation and

Market Report for 2009 state that there were many factors contributing to lower levels of participation and lower revenues in the Economic Program, including lower prices, lower loads and improved measurement and verification. The Market Monitor's Barriers to Demand Side Response in PJM report states that the evidence does not support the claim that the removal of the incentive program resulted in a reduction of activity in the Economic Program.[7] Although the Commission is rightfully concerned to promote increased participation in economic demand side demand side programs, and to be concerned when such participation drops, the Commission should regard efficient, market based pricing as the guiding principle for the regulation of the organized wholesale markets. The Commission has a variety of policy tools available to promote greater participation in economic

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lower revenues in the Economic Program, including lower price levels in 2009, lower load levels, and improved measurement and verification." Notably, while payments from the Economic Program have fallen substantially since 2007, capacity revenue for demand response has increased significantly (rising 114% to $303 million from 2008 to 2009.) Citing Monitoring Analytics, State of the Market Report for PJM, at 111 (March 11, 2010).] The NOPR also lacks a sufficient explanation of the "experience" that FERC has recently gained that would otherwise support the conclusion that the organized electric markets "fail to compensate demand response at levels that reflect the marginal value of the resource being used by the RTO or ISO to balance supply and demand." [citation omitted]").

[7] Barriers Report at 22.

demand side demand side response programs that do not require modifying market prices.

Perhaps more importantly, total compensation to demand side resources increased in 2009, despite the decline in compensation under the Economic Program. Although participation has declined in the Economic Load Response Program, the participation of Demand Resources in the RPM Capacity Market has increased substantially since its inception in 2007.[8,9] In 2009, while payments from the Economic Program decreased from 2008 by $26 million or 96 percent, from $27.7 million to $1.2 million, capacity market revenue increased from 2008 by $161 million or 114 percent, from $141 million to $303 million. Synchronized Reserve credits decreased by $1.1 million from 2008 to 2009, from $5.1 million to $4.0 million. Thus, total credits in PJM Load Response Programs from 2008 to 2009 increased 77 percent, from $174 million to $308 million.[10] See Figure 1.

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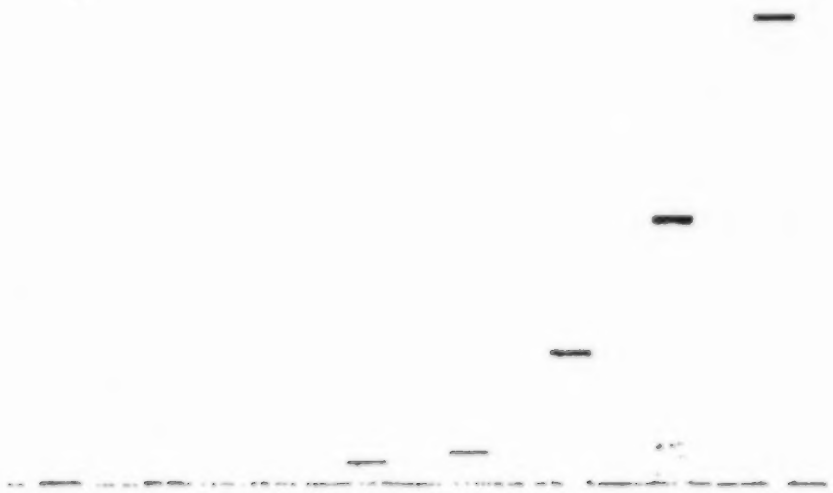
[8] 2009 State of the Market Report for PJM at 121 & Table 2-105.

[9] See 2009 State of the Market Report for PJM at 122 & Table 2-106.

[10] *See* 2009 State of the Market Report for PJM at 305–306.

Figure 1 Demand Response revenue by market: Calendar Years 2002 through 2009

Figure 1 Demand Response revenue by market: Calendar Years 2002 through 2009



II. CONCLUSION

The Market Monitor respectfully requests that the Commission accept and afford due consideration to these comments as it resolves the issues addressed in the NOPR.

Respectfully submitted,

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Dated: May 13, 2010

UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. RM10-17-000

DEMAND RESPONSE COMPENSATION IN ORGANIZED
WHOLESALE ENERGY MARKETS

May 14, 2010

Joint Comments of Public Interest Organizations On Notice of Proposed rulemaking (NOPR)

Introduction & Summary of Comments

1. Public Interest Organizations (PIOs)[1] respectfully submit these comments in support of the Commission's proposed rule. Establishing a compensation approach that requires payment of full locational marginal price (LMP) in all hours for demand response (DR) resources participating in organized wholesale energy markets is a critical step

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[1] ***Center for Energy Efficiency and Renewable Technologies, Citizens Utility Board of Wisconsin, Clean Wisconsin, Conservation Law Foundation, Environmental Defense Fund, Environmental Law and Policy Center, Fresh Energy, Izaak Walton League of America, Michigan Environmental Council, Natural Resources Defense Council, Pace Energy & Climate Center, Project for Sustainable FERC Energy Policy, Sierra Club, The Stella Group, Ltd, Union of Concerned Scientists.***

forward.[2] All ISOs/RTOs with tariff provisions allowing for DR participation in their energy markets should be required to pay full LMP to the DR resources that respond.

2. PIOs consider the payment of full LMP to DR resources critical to reducing the economic barriers to full DR participation in energy markets, ensuring that DR resources receive compensation that is at least comparable to that of generation resources. This policy goal is important because DR provides significant public values to the electric system, including economic efficiency impacts, reduced system costs, less congestion, greater reliability, and assistance with integrating variable renewable energy resources into the grid.

3. Thus, PIOs urge the Commission to adopt its proposed rule. LMP compensation will enable DR to provide greater system-wide economic, reliability and environmental benefits, and it will remove a major barrier to DR participation by providing price stability and compensation that is more adequate and comparable to the compensation paid to generation resources.

4. In addition to our general comments on the Commission's proposed new rule, PIOs provide responses to the direct questions posed in the Commission's NOPR and address some of the concerns raised in Commissioner

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[2] PIOs' support of full LMP compensation for all DR is based on the assumption that DR participating in the market is real and actually occurs. Participating DR resources must establish clear and predetermined baselines and utilize robust and accepted measurement and verification (M&V) protocols.

Moeller's dissenting opinion. We appreciate this opportunity to share our views on this important Commission proposal.

I. Increased DR Participation in Wholesale Energy Markets Provides Significant Economic, Reliability and Environmental Benefits to the Electric System

A. Economic and Reliability Benefits of Increased DR Participation

5. As the Commission noted in Order 719-A, decreasing demand has many important economic impacts on the electric system, including lower wholesale and retail prices, less price volatility, lower energy production costs, reduced market power, and enhanced system reliability.[3] These impacts produce a more efficient and lower cost power system for customers.

6. Increased DR participation in wholesale energy markets reduces wholesale and retail prices. Noting that DR has both direct and indirect impacts on wholesale prices, the Commission has stated that the direct impacts occur when DR is bid directly into the wholesale market and lowers market prices, and the indirect impacts occur at the retail level when a load-serving entity buys lower cost power in the wholesale market.[4] Citing a recent ISO-RTO Council Report, the NOPR notes the dramatic impacts on wholesale prices that a modest 3% load reduction in the 100 highest

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[3] Order 719-A, "Wholesale Competition in Regional with Organized Electric Markets," ¶ 47, July 16, 2009.

[4] See *id.*

peak hours produces—a price decline of six to 12 percent.[5] A 2007 Brattle Group Analysis, which quantified the market impacts of a 3% load curtailment in five PJM zones during the top twenty 5-hour price blocks in 2005, found that the 3% curtailment yielded energy market price reductions of $8-$25 per MWh or 5%-8% on average.[6] Finally, a recent analysis of price-responsive demand (PRD) participation in the ISO-New England day-ahead energy market showed that if all available PRD had been able to participate in the top 5% (or top 10%) of hours in 2008, the ISO would have saved $280 million (or $440) million respectively.[7] The analysis also concluded that PRD participation in the top 10% of hours would have reduced the ISO's 2008 system peak load by approximately 2000 MWs.[8]

7. Increased DR participation reduces the costs of delivering energy to customers. The Commission notes that DR tends to flatten an area's load profile, which in turn may reduce the need to construct and use more costly resources

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[5] See Notice of Proposed Rulemaking, *Demand Response Compensation in Organized Electric Wholesale Energy Markets*, Docket No. RM10-17-000, March 18, 2010, p. 4.

[6] See *Quantifying Demand Response Benefits in PJM*, a report by the Brattle Group prepared for PJM Interconnection and the Mid-Atlantic Distributed Resource Initiative (MADRI), January 29, 2007, pp. 2-3. The report also found that if all load were exposed to spot prices, the entire PJM system could save between $65 million and $203 million per year, and that impacts could be even larger if greater amounts of DR participation were achieved.

[7] See *Impact of PRD participation in day-ahead energy market*, A Memorandum by Synapse Energy Economics, October 16, 2009.

[8] See *id.*, p. 5.

during periods of high demand.[9] In addition, increasing the presence of DR provides market participants with better information about where they should and should not construct grid upgrades.[10] The overall effect is to lower the average cost of producing and delivering electric power to customers.

8. Increased DR participation reduces the ability of generators to exercise market power. The more DR available to participate in energy markets to reduce demand in response to prices, the greater the downward pressure on generator bidding strategies. Generators face increased risk that their resources will not be dispatched if they bid a price that is too high or if they withhold some resources in an effort to limit overall supply and force prices higher.[11]

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[9] See Order 719-A, supra, fn.3.

[10] See *id*, fn.74. DR participation may reduce or eliminate the need to construct grid upgrades as demonstrated by a Virginia Hearing Examiner's decision that the PATH line will no longer be required in 2014, as originally thought, due to recent modeling analyses that accounted for DR resources. See Behr, Peter, *Energy Conservation Helps Stymie a Major Transmission Line*, The New York Times, January 6, 2010.

[11] See *id*. See also, *Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them*, A Report to the United States Congress by the US Department of Energy, February 2006. The report states that DR improves resource efficiency of electricity production due to closer alignment between customers' electricity prices and the value they place on electricity. The increased efficiency creates, among others, "Market Performance Benefits," which refer to DR's value in mitigating suppliers' abilities to exercise market power by raising power prices significantly above production costs. See DOE Report, p. vi.

9. Increased DR participation also enhances system reliability by providing system operators greater flexibility. Reducing electricity demand at critical times, for example, when a system operator dispatches DR on short notice to offset the unexpected loss of a generator or transmission line, helps to return the electric system to normal operating status very quickly.[12]

B. Environmental & Renewable Energy Benefits of Increased DR Participation

10. DR participation in the energy market can also provide load balancing services. The NOPR clearly notes DR's potential to address the resource management and grid operation challenges surrounding unexpected loss of generation, such as the February 26 2008 ERCOT event where the system operator called on all available DR resources to offset reduced wind generation, and 1200 MWs of load responded within ten minutes, bringing ERCOT back into balance.[13]

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[12] See id, fn.76. (citing FERC Staff Report, "Assessment of Demand Response and Advanced Metering," December 2008, pp. 50-53, which described the use of DR during system emergencies in 2007 to ensure system reliability. For example, during a California heat wave in August 2007, consumers responded to California's voluntary Flex Alert program by delivering 1000 MW of DR and averting a Stage 2 emergency. See *id.*, pp. 50-51. Further examples include PJM's and NY ISO's requesting and receiving necessary DR services during peak summer periods of 2007 pursuant to their respective emergency demand response programs. See *id.*, p. 52).

[13] See NOPR on DR Compensation, supra, fn.5, pp. 5-6, fn. 15.

11. In addition, DR can shift energy usage to periods of high variable energy resource (VER) output. For example, DR can often shift the timing of certain energy usage to absorb generation from wind resources that may produce much of their output at night. Enabling energy usage to be shifted from peak periods to off peak periods offers multiple grid benefits, including reducing peak loads and prices and increasing the grid's load factor, resulting in a more efficient grid.

12. Finally, increased DR participation helps to preserve the environmental benefits of integrating renewable VERs into the grid. Most DR does not emit carbon dioxide, nitrogen oxide, or other air pollutants, and it can displace fossil-based generation for ramping VERs, thereby preserving the environmental benefits of VER integration.[14]

II. The Proposed Rule Would Help to Eliminate Economic Barriers to DR Participation

A. The Proposed Rule would enhance price certainty and facilitate DR investment

13. Relative certainty about the opportunity for recovering the costs of capital investments is critical on both sides of the electric meter. Having an understandable and rela-

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[14] In addition, though primarily intended to reduce peak demand through load reduction and/or load shifting, demand response services (including mechanisms such as dynamic pricing) can often result in a degree of energy savings and, subsequently, reductions in carbon emissions. See *The Green Grid, Energy Savings and Carbon Emission Reductions Enabled by a Smart Grid*, a Report by Electric Power Research Institute, June 2008, p. 4-3.

tively certain basis for the assessment of product prices is as important for DR investments as for generation investments. Frequent changes to compensation rules create barriers for aggregators who have to seek out and persuade customers to become DR resources.

14. Uncertainty about the rules for and length of DR participation in the marketplace, including the range of prices to be paid for the electric services provided creates a significant economic barrier to DR investment and limits the ability of DR providers to participate in energy markets. The NOPR appropriately characterizes the barrier to participation produced by inconsistent compensation noting that market participants have confirmed that they must have confidence that appropriate price signals will be sustained by stable competitive pricing structures before making investments in DR.[15]

15. Different approaches to and rules for DR pricing and participation in adjacent markets and interconnected system makes these barriers even more daunting. Such differences make it more difficult for aggregators of DR resources to implement broadly effective business models and for end use customers operating in multiple markets to minimize the costs of DR participation.

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[15] See NOPR on DR Compensation, supra, fn.5, pp. 10-11 (referring to Transcript of Order No. 719 Technical Conference, p. 24, *Statement of James Eber, Director of Demand Response at Commonwealth Edison*).

B. Full LMP more adequately compensates DR providers for their costs and risks

16. DR providers incur costs that exceed the cost savings related to foregoing energy use, and they must be compensated for those costs in order to participate in the energy market. To pay less than the LMP cost savings for foregone energy use often under compensates DR providers for the direct costs they incur and always under compensates them for the electric services they provide.

17. End use customer representatives have described the costs they incur when they reduce demand in response to emergency events or price signals. When an industrial customer curtails its usage during a high-priced period, it typically makes up lost production in another period, and it bears the risk that the difference in price between the period of curtailment and the period when the production is "made up" will justify the cost of the curtailment. In addition, industrial customers often need to consume additional MWhs in later periods due to the loss of process efficiency that results from starting and stopping manufacturing equipment.[16]

18. Given the significant system benefits resulting from DR services, it might be reasonable to pay LMP plus a premium for DR market participation in many circumstances. However, paying the full LMP for kWhs provided by DR is a

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[16] Summary Remarks of Larry Stalica, Vice President, Linde Energy Services, Inc., Technical Conference, May 21, 2008, pp. 2-3. Other fixed shut-down and start-up costs include labor, raw material losses and semi-finished product losses which could be significant.

reasonable proxy payment for its market services, and it should encourage DR providers to participate more broadly in the energy markets.

C. Full LMP helps to Ensure Comparable Compensation

19. Generators are paid the full LMP for their services when their bids clear in the energy market. DR resources should, at a minimum, be paid comparably. In addition, because generators are paid the LMP in all hours in which they provide energy services, DR providers should receive comparable compensation in all hours in which their bids are accepted and their services are provided.

20. Failure to compensate DR resources comparably in all hours in which they provide grid services will continue to under-compensate them for many of the externality costs they incur (discussed in paragraphs 16 and 17 above) when they do respond, driving valuable, cost effective resources from the marketplace.

III. PIO Responses to Specific Commission Questions

Whether current compensation is procuring adequate amounts of DR?

21. The exodus of DR from PJM's economic load response program after the elimination of full LMP compensation indicates the answer is "no."[17] Currently, DR providers

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[17] Until December 2007, PJM's Economic Load Response Program paid full LMP to all DR resources when LMP equaled or exceeded $75/MWh. According to PJM's Market Monitor, beginning in January 2008, after PJM reduced compensation to DR resources below LMP, settled

collectively play a very small role in wholesale markets (NOPR, p. 10) even though the potential for DR participation is very large.

The relative merits of alternative approaches to compensating DRRs?

22. Compensation at full LMP recognizes the reliability, economic and environmental benefits that DR provides to the system and market participants. Compensation of DR at LMP + x may be justified by DR's system benefits, but payment of less than full LMP cannot be justified as just and reasonable.[18]

Whether a reduction in consumption is equivalent to an increase in power production, thereby requiring that compensation should be comparable?

23. A reduction in energy consumption meets essential system needs, including load balancing and resource adequacy, in a manner comparable to increased power production and, thus, should be compensated comparably. Reduc-

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demand reductions decreased by almost 37%, from 714,200 MWh to 458,300 MWh, and the decline continued throughout the period of the Market Monitor's analysis (March 2009). See NOPR on DR Compensation, *supra*, fn.5, p. 11-12 (referring to Monitoring Analytics, *Barriers to Demand Side Response in PJM*, July 1, 2009, p. 22).

[18] See NOPR on DR Compensation, *supra*, fn.5, p. 12. The Commission expresses concern that inadequate DR participation, now and in the future, may be the result of compensation that is no longer just and reasonable, because the existing and varying levels of compensation generally fail to reflect the marginal value of demand response resources to ISO and RTO energy markets.

tions in consumption, however, may provide additional reliability, economic and environmental benefits that increases in power production do not provide and, thus, may reasonably be compensated at higher levels under those circumstances.

Whether paying LMP to DRRs is comparable to generator compensation?

24. Yes. Because DRRs and generators meet identical marketplace needs, both should be paid the marginal price for the services they provide to the market. Payment adjustments to LMP may be appropriate for either type of resource as in the case, for example, of ISO-NE's Peak Energy Rent (PER) mechanism for Capacity Supply Obligation (CSO) resources.[19]

Whether LMP should be paid to DRRs in all hours?

25. DR should be allowed to participate in energy markets and be paid LMP in all hours in which it is the most cost-effective and reliable resource to dispatch. LMP should apply in all hours DR clears in the Day-Ahead or Real-Time Energy Markets, and DR resources should be selected after consideration of total daily market costs/benefits.

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[19] The PER mechanism reduces a resource's capacity payments by the number of hours in which the market clearing price exceeds a predetermined baseline. In New England, that baseline is set by the MWh price for a 22,000 btu heat rate unit (and includes a periodically adjusted price of gas). The PER mechanism was part of the overall Forward Capacity Market settlement and is intended to provide load with a protection or hedge against high-priced hours in the wholesale energy market.

Whether a universal compensation requirement is appropriate or whether the Commission should allow regional variations in compensation or even non-compensation in RTOs?

26. A universal compensation requirement is appropriate because it will remove economic, educational and institutional barriers that currently inhibit potential DR providers from entering markets due to the cost and time required to learn distinct sets of market rules. Adjustments to LMP may be appropriate due to other compensation mechanism in place in the region (see ¶ 24 above)

Whether and when should the Commission conduct reviews of DR compensation?

27. The Commission should conduct reviews of DR compensation within each RTO once the RTO has achieved substantial market penetration or, after a specific period of time, if an RTO has not achieved substantial market penetration. PIOs suggest review after an RTO achieves penetration in the top 10% of hours and after 12 months in the case of RTOs that do not achieve penetration in the top 5% of hours. ISO/RTO Annual Market Reports should review DR as well as generation resource participation.

Whether key terminology in the proposed new rule is sufficiently defined?

28. PIOs believe that the common meaning of these terms provide sufficient clarity. "Expected Levels" means load as anticipated without DR participation. "Price Signals" means energy prices during peak periods. And, "Market Prices" means Day-ahead LMPs or Real-time LMPs.

IV. PIO Responses to Commissioner Moeller's Concerns

The NOPR failed to provide evidence that current compensation for DR is not just and reasonable.

29. Ample evidence is provided in Docket No. EL09-68-000 and the Commission has taken administrative notice of that evidence. It cannot be just and reasonable to pay one class of market participants less than another class for providing comparable market services.

The debate is between whether DR should be paid LMP or should realize the value of LMP

30. The NOPR cites Larry Stalica, who stated that "the mere avoidance of electricity prices often provides insufficient value to offset these real costs. Demand Response will not occur if customers do not have an economic incentive to reduce consumption[20]." DR can avoid LMP costs today without changing any rules. However, if DR avoids LMP costs *and* receives a payment, then more DR providers will be able to participate because the payment will cover some of their externality costs. In an ideal world, payment should recognize all of the externalities.

Should DR be required to pay into the market when LMP is negative?

31. Because DR would have no reason to bid into the energy market when LMP is negative, PIOs believe this would never be an issue.

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[20] NOPR on DR Compensation, *supra*, fn.5, p. 11, fn.32.

Whether a uniform compensation requirement may discourage regions from developing organized market structures?

32. There is no evidence that regions without organized markets would decide against developing such markets based upon the likelihood of a uniform compensation scheme for DR.

Whether barriers to DR participation should be addressed at the retail level?

33. Barriers to DR should be addressed at both the retail and wholesale levels. Certain barriers may be best addressed at the wholesale level: e.g., the lack of standard baseline M&V procedures and eligibility rules has limited DR participation.

V. Conclusion

Due to the economic, reliability and environmental benefits that increased DR participation will provide to the electric system, and because payment of full LMP will help to eliminate economic barriers to increased DR participation, PIOs urge the Commission to adopt the proposed rule to compensate DR resources at the full LMP in all hours in which they participate in the energy markets.

Respectfully Submitted,

[Electronically Filed]

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UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. RM10-17-000

DEMAND RESPONSE COMPENSATION IN ORGANIZED
WHOLESALE ENERGY MARKETS

May 14, 2010

REQUEST FOR LEAVE TO SUBMIT ONE DAY OUR-OF-TIME AND COMMENTS OF OLD DOMINION ELECTRIC COOPERATIVE ON NOTICE OF PROPOSED RULEMAKING

Pursuant to Rule 212 of the Commission's Rules of Practice and Procedure, Old Dominion Electric Cooperative ("ODEC") requests leave to submit these comments one day out-of-time. Despite its best efforts, ODEC was not able to timely file its comments on May 13 and, therefore, seeks leave to submit the comments today. Given that the comments are submitted a single day late, ODEC submits that acceptance of these comments will not unduly prejudice or burden any entity, nor should it unduly delay the Commission's consideration and decision on the issue of demand response compensation in this rulemaking proceeding.

I. INTRODUCTION

ODEC appreciates the opportunity to submit comments on the Commission's Notice of Proposed Rulemaking (NOPR) issued in this proceeding on March 18, 2010.[1] ODEC is an ardent supporter of demand response and is appreciative of the Commission's focus on this critical area. As a not-for profit power supply cooperative operating in organized markets since their conception, ODEC offers a unique, customer-focused perspective on these markets in general and PJM Interconnection, L.L.C. ("PJM") in particular.

The NOPR proposes to amend Chapter I, Title 18, Section 35.28 of the *Code of Federal Regulations* by adding a new paragraph (g)(1)(v) which would state that "each Commission approved ISO and RTO that has a tariff provision providing for participation of demand response resources in its energy market must pay demand response resources, in all hours, the market price for energy, i.e., full LMP, for demand reductions made in response to price signals."[2] ODEC offers the following comments on this proposed regulation and responses to the questions set forth in the NOPR based on ODEC's experience in PJM and with its eleven member-owner electric distribution cooperatives in Virginia, Maryland and Delaware.

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[1] *Demand Response Compensation in Organized Wholesale Energy Markets*, 75 Fed. Reg. 15362 (March 28, 2010) ("Notice of Proposed Rulemaking" or "NOPR").

[2] NOPR at P 11.

II. BACKGROUND

ODEC's member-owners are not-for-profit electric cooperatives owned by the consumer members they serve, with the goal of serving their load in a least-cost manner using ODEC to procure wholesale power. ODEC's member-owners support increased demand elasticity through proper demand response and have successfully implemented demand reduction programs since the late 1980s resulting in an approximate 10% reduction in peak demand.[3] ODEC's member-owners have largely created this reduction in peak demand by exercising direct load control through water heater and air conditioner switches and through the use of voltage control and interruptible rates. ODEC and its member-owners continue to look for ways to encourage demand response and energy efficiency and to develop appropriate measurement and verification standards.

As member-owned and member-governed private companies, the cooperatives' primary goal is to provide a reliable power supply at the lowest possible cost. Demand response in its many configurations has proven to be critical to any cost-cutting effort because it permits cooperatives to shape their load and to smooth

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[3] ODEC and its member-owners have achieved far greater demand response penetration than the average PJM load serving entity. The approximate 10% reduction by ODEC and its member-owners is far greater than the 2009 PJM system average of 5.75% of Demand Resources in PJM.

their peaks which can reduce the cost of power. In organized markets, demand response is an important component of managing power supply as it serves as a flexible hedge that cooperatives can utilize to help shape load, which reduces contractual demand costs, reduces both capacity and energy costs, and reduces their costs and risks. In the cooperative structure, there is no competition between maximizing shareholder value and providing customers the lowest possible cost as the owners are the customers. Therefore, all benefits coming from retail demand response activities go directly to the member-owners.

ODEC also supports competitive wholesale markets because competitive markets offer flexible choices for cheaper supply driven by competition. A competitive wholesale supply is but one of three major components necessary to achieve a competitive wholesale market and is largely in place in the RTO/ISO structure. The other two components necessary for competitive markets are: (1) adequate transmission infrastructure which facilitates competition by allowing suppliers and buyers to meet on a level playing field, and making supply from all generation resources available to all buyers and (2) demand elasticity. These two components are equally important but are not as fully developed.

In the competitive model, demand elasticity is, and should be, on the load (demand) side of the demand and supply curve interaction. Demand elasticity is necessary to complete wholesale markets because it

allows demand to self-regulate how much it is willing to pay for a commodity (not supply it) by reducing its load. Complex constructs, such as the existing wholesale demand response programs, artificially treat demand response as a resource rather than as load, which detracts from the simple eloquence of the competitive market and, due to its complexity, will be ineffective in getting all responsive load to ultimately exhibit elastic qualities (*i.e.*, respond to changes in price).

Another important aspect of elastic demand is its ability to mitigate the effects of market power. Demand elasticity transmits necessary price reducing responses to offset supply-side resources that may want to increase prices. Demand elasticity mitigates these market effects only when demand response is incorporated as bids on the load side of the market and not as resource offers on the supply side of the market.

Artificially treating demand response as a resource, especially through third party intermediaries such as aggregators of retail customers ("ARC"), gives demand response acting as a resource the same incentive to increase supply prices as generation resources. The complexities and inefficiencies of a third party intermediary takes value from load (the ARC fee) and also allows ARCs to behave in a manner which drives up wholesale prices without scrutiny from load as the customer does not understand or directly receive signals from the wholesale market.

The proper end-state for demand response programs is one in which demand response is bid into the

market on the load or demand side and is not treated as a resource on the supply side. However, the next step in this evolutionary process must occur at the retail level. Retail rates and smart-metering infrastructure do not currently have sufficient penetration in the retail arena to allow the price transparency needed for load to directly respond to price. Due to this lack of infrastructure and limited retail pricing options at the local level, intermediate constructs are necessary to allow demand response to occur now and some of the intermediary solutions involve treating demand response as a resource in the wholesale markets. The current RTO/ISO demand response programs serve this purpose.

However, wholesale level demand response programs should not hinder and should possibly incent retail programs and structures at the local level where demand response is treated as a reduction in load rather than a resource and more effectively plays its critical demand elasticity role. From this perspective, as a cooperative utility in PJM whose members have used demand response as a mechanism to satisfy their obligation to meet load requirements at the lowest possible cost, ODEC offers these comments regarding demand response compensation in the current wholesale markets and recommends next steps in the transition to a fully functioning demand side at the local level.

III. EXECUTIVE SUMMARY

ODEC appreciates the Commission's commitment to improving competitiveness in wholesale markets by facilitating demand response participation. However, ODEC does not support the Commission's proposal to compensate demand response resources at full locational marginal price ("LMP"), or the Commission's proposal to implement a standard compensation mechanism for all RTOs and ISOs. As discussed in detail in these comments, for at least PJM, paying a retail demand response provider LMP minus the avoided generation cost or G is an acceptable monetary adjustment to allow retail demand resources to face a wholesale price signal until such time as there is sufficient demand response at the local level. This provides the retail responder with a closer approximation of the value of avoiding the wholesale cost. ODEC also recommends that rather than mandate a single compensation mechanism for all RTOs and ISOs, the Commission should allow each RTO and ISO to work with its stakeholders to develop the appropriate transitional demand response compensation mechanism.

The Commission's proposal to compensate demand response at full LMP will lead to compensation that is contrary to the Commission's stated goal of facilitating demand response participation in order to improve competitiveness in wholesale markets. Specifically, demand response participating in RTO or ISO-administered markets is not comparable to generation resources in those same markets, in terms of their

respective roles in the RTO and ISO markets, as well as the current inability of demand response to be subject to dispatch and other requirements of generation resources. Instead, demand response should be viewed on the "demand" side of the meter, as opposed to the "resource" side. Given that demand response is not comparable to generation resources in performance, generator compensation should not be the basis for the compensation structure for demand response. Instead, demand response should receive the value of avoiding the individual load serving entity's ("LSE") market price which in the PJM program is G.

Further, in order to ensure that the Commission's demand response compensation rule does not hinder development of demand response at the local level on the load (demand) side of the demand and supply curve dynamic, it is imperative that any demand response compensation mechanism (wherein demand is treated as a resource) be adopted as a transitional mechanism, to sunset at such time as sufficient demand elasticity occurs at the local level. While PJM's demand response program has its flaws, ODEC believes the PJM LMP minus G compensation provides a reasonable, transitional surrogate to approximate the benefit of retail load curtailing to avoid market prices.

In addition to not appropriately replicating the value of demand response, ODEC is concerned that implementation of the Commission's proposed compensation of full LMP will overcompensate retail demand response, introduce market inefficiencies and cross-

subsidization and have the unintended consequence of impeding necessary changes at the retail level. Each of these concerns is addressed more fully in these Comments. These Comments also respond to the specific questions set forth in the NOPR, many of which are addressed in the general comments and recommendations below.

IV. COMMENTS

A. Demand response participating in RTO or ISO economic programs is not a "resource" comparable to generation resources in the wholesale market.

For the purpose of these comments, ODEC subscribes to the following definition of demand response as set forth in the Commission's Regulations:

> Demand response means a reduction in the consumption of electric energy by customers from their expected consumption in response to an increase in the price of electric energy or to incentive payments designed to induce lower consumption of electric energy.[4]

Based on this definition, it is clear that demand response is a voluntary action based on economic factors. Additionally, ODEC does not view distributed generation as demand response. Further, for the purpose of these comments, ODEC defines "demand resource" as the artificial treatment of demand response as a re-

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[4] 18 C.F.R § 35.28(b)(4)(2009).

source in the wholesale marketplace, rather than treating demand response as a reduction in load.

As discussed throughout these comments, demand response treated as a demand resource is far less preferred than treating demand response as a local reduction in load. However, ODEC recognizes that treating demand response as a resource is a necessary transitional measure. Assuming the albeit subpar treatment of demand response as a demand resource, the logical question arises regarding how to treat demand response viewed as a resource in a manner comparable to generation resources. Within the definitional boundaries set forth above for "demand response" and "demand resource", demand resources are not equivalent to generation resources. However, accepting that demand response programs will continue as a transitional step in the evolution of demand response, there should be comparability in compensation and performance between demand resources and generation resources.

As explained more fully below, in the PJM program demand resources do receive comparable compensation to adjust for the lack of market continuity whereby wholesale costs are not adequately reflected on a more granular basis in retail rates. Under this lack of continuity, retail customers are unable to avoid the full cost of wholesale supply, which is very roughly LMP minus G, unless treated as demand resources in the wholesale marketplace. The LMP minus G compensation, in PJM, is the workaround to the existing

lack of continuity between wholesale and retail pricing.[5]

Demand resources currently have less stringent performance requirements than generation resources, and while these two resources can never be equal, ISO and RTO rules must be modified to require comparable performance from demand resources and generation resources.

1. **Demand resources do not serve the same role as generation resources in the wholesale market.**

Generation resources and demand response do not serve the same roles in the wholesale market and the overall concept of considering demand response as a resource can have unintended consequences leading to market inefficiencies, wealth transfers and cross subsidies. As previously indicated, demand response serves a critical role in achieving demand elasticity, which is essential for creating competitive markets, but only serves this role effectively when introduced into wholesale markets as a demand function and not as a demand resource.

Additionally, generation resources have as a core business function the supply of electricity for load consumption, whereas demand resources do not have such

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[5] ODEC notes that there are some LMP-based retail customers on the PJM system, and the workaround compensation is neither needed nor used for LMP-based retail customers because they are capable of avoiding the full cost of wholesale supply through reduction in load.

electricity business imperative. Far from an imperative to serve as a resource, demand resources have a functional objective to consume in a cost-effective manner while serving their core business function. For example, a commercial customer may choose not to curtail in one expensive hour one day because of pre-arranged labor, whereas, in a less expensive hour on another day, it might choose to curtail because of labor flexibility. The implications of this difference in role are profound. A generation resource is likely to be an available resource in an enduring fashion through electricity market upturns and downturns because its core business is to produce and sell electricity. Generation resources are also capital intensive, which creates a much larger "barrier to exit" than exists for a demand resource. This large barrier to exit also makes generation resources more stable and enduring as available resources. Due to the highly inelastic nature of load today, quick retreats of demand resources from the marketplace and worse yet, potential retirement of generation resources driven by increased reliance on demand resources, there is an increased potential of resource adequacy reliability violations as well as increased and costly price volatility as described further in Section IV.A.3., below.

The difference in roles between generation resources and demand resources is portrayed clearly in power pool interactions. Larger interconnections are largely in place to create economies of scale in reserves. Demand resources do not provide the same

value as generation resources when calculating reserve margin requirements brought about by larger interconnections. When calculating the reserve margins for a control area, there is reliance upon the existence of support from generation resources in neighboring control areas; however, demand resources from neighboring control areas are not relied upon at all. Demand resources are not expected to secure transmission service, are not bus locational, nor are they considered as inclined to sell power into neighboring control areas to prevent emergency conditions because supplying electricity is not a business imperative for demand resources. ODEC also notes that with regard to economic power pool-to-power pool transactions demand resources do not participate. Generation resources contribute to larger marketplaces because they do participate in power pool-to-power pool transactions. This increased market size brought about by generation resources (yet hindered by demand resources) leads to increased market efficiencies and reduced overall costs to load.

2. **Demand resources are not subject to the same rules as generation resources in the wholesale market.**

The rules under which demand response being treated as a resource operate create disparities between generation resources and demand resources. Unlike generation resources that are dispatched by system operators, demand response is a voluntary reduction in electric consumption in response to price

and to the end-use facility operational needs, such as an industrial customer needing to immediately complete a production run to fulfill a customer order. The amount of load reduction is determined by the responder and can vary from hour to hour in PJM's program. There is no potential cost penalty for demand resources if they choose not to curtail, and a responder's curtailment decision is generally made without consideration of the grid's operation and stability.

In PJM, there are additional rules that are more favorable toward demand resources as compared to generation resources. For example, demand resources that clear in PJM's Reliability Pricing Model ("RPM") can only be required to perform 10 times and only for emergency purposes over the summer. Additionally, these same resources have one-hour and two-hour call times, which raises reliability concerns for instances where emergencies happen quickly, such as large and sudden generator outages. Further, RPM demand resources are not subject to the must-offer requirement into the day-ahead energy market that exists for generation resources, which are required to bid into the day-ahead energy market on economic schedules. In the 2009 PJM State of the Market Report, the Market Monitor states on page 49 that, "The obligation to offer energy in the Day-Ahead Energy Market should be applied without exception to all capacity resources, including both generation and demand resources. This means that capacity resources must be available every hour of the year at a com-

petitive price. Demand resources that agree to interrupt only 10 days per year are not capacity resources."

Additional critical disparities in the PJM rules exist between generation resources and demand resources in the area of market power mitigation rules. Even though curtailment service providers (the third parties selling demand resources in the PJM marketplace) have the same incentives to attain higher rather than lower market prices, demand resources are not subject to market power mitigation rules. This disparity can lead to potential gouging of all load in the PJM cleared marketplace given that demand resources can set prices in PJM. Demand resources must also be subject to the comparable testing and verification rules to prevent market manipulation. To this point, the 2009 State of the Market report for PJM states on page 6 as follows:

> Load Management test results are submitted by CSPs directly to PJM. The test results consist of metered load data provided by the CSP which are compared to some baseline consumption level or firm service level determined by LM participation type. There is no physical or technical oversight or verification by PJM or by the relevant LSE of actual testing. PJM screens the data for unreasonable test results, but relies on the CSP to submit accurate metered load data for the testing period with no verification. This form of testing is not an adequate measurement and verification

protocol to ensure that demand side capacity resources can reliably reduce during a system emergency. The MMU recommends that the testing program be modified to require verification of test methods and results.

Thus, in order to be considered comparable to generation resources, demand resources participating in the wholesale energy markets would have to be dispatchable and subject to requirements that are comparable to generation resources. This is not the case at this time.

3. **Demand response does not provide the same level of economic utility to the wholesale market as generation resources.**

As described in part 1 above, demand response has a critical demand elasticity role that is not served by generation resources or for that matter by demand response that is treated as a resource. This section addresses how well demand response that is treated as a resource functions when compared to generation resources.

Voluntary and non-dispatchable demand response does not provide as much economic utility as generation resources in the wholesale markets. Demand resources are not of an enduring nature and tend to come and go very quickly in response to price or other non-energy price variables. Conversely, generation resources are extremely capital intensive and tend to remain available as a resource through the upswing

and downswing cycles in electricity prices. As demand resource penetration deepens, relying on demand response as a resource that is equivalent to generation could lead to shortages of supply and to resource adequacy reliability violations if demand resources quickly exit the market. As generation resources require a long lead time to construct, reliability and adequacy problems may occur if generation resources are displaced by demand resources and retire or if the price signal necessary to incent new construction is not present. Paying demand resources full LMP would exacerbate this problem as the subsidy would incent non-economic behavior which would artificially lower LMP prices and prevent needed capital investment in generation.

In contrast to wholesale power producers, retail customers are consumers of electricity and place greater value on purchasing electricity than they do on curtailing usage. Wholesale power producers, on the other hand, are in the business of producing electricity and therefore place greater value on the sale of their product than the consumer places on avoiding or deferring usage. Thus under the current market rules and inherently, demand resources do not have the same incentives to perform as generation resources and treating them as comparable resources with similar innate performance drivers will interfere with efficient outcomes since demand resources may not avail themselves of a curtailment opportunity at pre-

cisely the time when the RTO/ISO operations department expects them to perform.

The decision whether or not to curtail in response to price rests entirely with the customer, the question then becomes what compensation should the customer receive for that curtailment? In this regard, ODEC supports Commissioner Moeller's statement that "while there appears to be no disagreement that the correct price signal for all customers is the LMP, the debate centers on whether demand response resources should be *paid* the LMP *or* should realize the *value* of LMP if they choose to reduce demand."[6] As previously indicated, demand resources are not dispatched by the system operator and are not subject to requirements that are comparable to generation resources. However, as explained below, currently demand resources in PJM are paid LMP minus G which allows them to realize the value of their curtailment as being comparable to the compensation paid to generation resources.

B. Until such time as sufficient demand response occurs at the local level, LMP minus the avoided generation cost (G) is an acceptable compensation for demand resources.

Although not a perfect construct, paying a retail demand response provider LMP minus G is an acceptable monetary adjustment to allow retail demand re-

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[6] NOPR, Commissioner Moeller concurring in part, and dissenting in part at FN. 9.

sources to face a wholesale price signal until such time as there is sufficient demand response at the local level. This is the current compensation methodology in PJM and has been proposed by the Midwest Independent System Operator, Inc.[7] The Organization of MISO States also recognized this concept in comments filed in support of MISO's proposal to pay ARCs LMP minus the marginal foregone retail rate.[8]

Compensating retail demand responders at full LMP overpays the value of the avoided cost or G, results in cost shifting between different loads, and leads to increased prices for all load, without resulting in more efficient demand response programs.

1. **LMP minus G compensates demand resources comparably to generation resources**

Paying LMP minus G is an acceptable monetary adjustment for retail demand response, on an interim basis. The NOPR proposal to pay retail demand response participants full LMP over-compensates

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[7] In its filing proposing LMP minus the marginal foregone retail rate as the appropriate compensation for ARCs, the Midwest Independent System Operator "MTSO" agreed with these concerns and indicated that a proposal to pay full LMP was opposed by all LSE's and some state commissions as it would raise market prices and cross subsidies would occur between LSE's. *See* Midwest Independent System Operator, Inc. Filing RE Aggregator of Retail Customers, Docket No. ERI0-26-000 (October 2, 2009) at 15.

[8] Midwest Independent System Operator, Inc., Docket No. ER09-1949-002, Comments of the Organization of MISO States (November 5, 2009) at 3.

demand resources and is akin to paying a generator full LMP plus fuel costs. This is because the cost of the retail rate component associated with generation, "G", is analogous to fuel costs for a generator. The retail rate customer saves the cost of G or, in other words, avoids paying G, by not consuming. This is an economic benefit to the customer. If the customer then gets paid full LMP, the total benefit to the retail rate customer is LMP plus G. Additionally, ODEC is not proposing that transmission ("T") and distribution ("D") costs be removed from the compensation paid to demand resources because the system is planned as if the voluntary demand response did not occur so the customer still pays the T and D costs. LMP minus G reflects a reasonable approximation of the value to the customer for responding to market prices without compensating that customer for the cost of generation which that customer did not consume and therefore for which the customer did not pay. This payment does not reflect a subsidy or underpayment because it ensures that the customer receives a total benefit equal to the LMP (by combining the avoided cost of generation, G, with the resource payment of LMP minus G).

2. **Payment of full LMP would result in cost shifting between load groups.**

Currently, retail customers can participate in PJM's demand response programs either on their own or through an ARC. Participation in PJM's programs requires the customer to have meters capable of providing hourly data. All customer meters do not cur-

rently have this capability. Since most states have not engaged in full-scale deployment of smart meters, most of the customers that have meters capable of providing hourly data are large customers for whom the cost of a meter is small compared to the savings available by avoiding consumption during high priced hours even without the subsidy provided by paying full LMP. Since not all retail customers are currently able or willing to participate in wholesale programs, paying full LMP to demand resources results in cost shifting between different load groups and increased energy prices for all.

Commission Moeller also recognized these issues in the NOPR when he stated as follows:

> As mentioned in the preamble, the primary barrier to increased demand response is the disconnect between retail and wholesale prices and the remedy resides at the retail level where there is a lack of dynamic pricing. The approach embraced in the NOPR may also lead to a situation where residential ratepayers could be subsidizing other classes of service while unable to participate themselves in demand response programs. Absent attention to these issues, it will be difficult for any proposal to place generation and demand response on a precisely level playing field.[9]

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[9] NOPR, Commissioner Moeller concurring in part, and dissenting in part at 5.

ODEC agrees with this statement and, as explained more fully in Sections C and D below, believes that demand response is important for competitive markets and that demand elasticity required to reach enduring low rates can best be accomplished through retail price structures and technology.

3. **A decrease in demand response in PJM is not indicative of compensation that is not just and reasonable.**

In the NOPR, the Commission indicates that demand response resources react correspondingly to increases or decreases in payment and that in PJM a decrease in demand response was seen after compensation was decreased. The Commission goes on to state that "the Commission is now concerned that evidence of demand reductions in PJM, and inadequate demand response participation, now and in the future, may be the result of compensation that is no longer just and reasonable, because, as detailed below, the existing and varying levels of compensation generally fail to reflect the marginal value of demand response resources to ISO and RTO energy markets."[10]

ODEC disagrees with the conclusion that a reduction in demand response participation rates after the expiration of the subsidy[11] is indicative of a failure to

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[10] NOPR at P 10.

[11] On December 31, 2007, a temporary provision in the PJM Open Access Transmission Tariff allowing for payment of full LMP to

reflect the marginal value of demand response. As indicated by PJM's Independent Market Monitor ("IMM") "there were many factors contributing to the lower levels of participation and lower revenues in the Economic Program, including lower price levels in 2009, lower load levels and improved measurement and verification."[12] Thus while some resources may have chosen not to participate in PJM's demand response programs due to the expiration of the subsidy, which compensated demand resources beyond the economically efficient level, it is clear that a number of economic and market conditions also factor into a customer's decision whether or not to respond to price.

C. PJM's current economic demand response program provides a reasonable surrogate to approximate the benefit of retail load curtailing to avoid a market price until such time as the retail markets are developed.

As explained by PJM's IMM, the goal of PJM's Economic Program is to address the market failure in which customers do not pay the market price and engage in behavior that is inconsistent with the market price of electricity.[13] The IMM described the savings achieved by a reduction in usage:

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participants in the demand side program when the LMP was greater than $75 expired.

[12] 2009 State of the Market Report for PJM at 111.

[13] MMU White Paper: PJM Demand Side Response Program, PJM Market Monitoring Unit (December 4, 2007) at 1.

From a wholesale market perspective, in the absence of an Economic Program, for an individual customer on a standard fixed retail rate, the savings that result from a load reduction equal the generation component of the applicable retail rate. If the customer pays a retail rate that includes a generation component of $40 per MWh, from a wholesale power market perspective, the customer saves exactly $40 when load is reduced by 1 MWh.

If the customer paid the LMP for each MWh used, rather than the generation component of retail rates, the savings to the customer from a load reduction would equal the LMP. This is the appropriate price signal and this is the price signal that the Economic Program should be designed to replicate. This price signal does not reflect a subsidy.

From a wholesale power market perspective, in the absence of an Economic Program, for an LSE the savings that result from a customer reducing load equal the difference between the LMP and the generation component of retail rates. The LSE pays the hourly LMP to purchase the energy required to serve the customer at a fixed retail rate. In this case, the savings to the LSE from a reduction of 1 MWh by the customer equal the difference between the cost not incurred by the LSE, the LMP, and the revenue not received, the generation component of the retail rate. The LSE avoids paying the LMP to purchase a MW but the LSE loses the revenue from the generation component of retail rates.

> If the LSE pays the LMP to purchase energy to serve the customer, the wholesale-related savings received by the LSE will equal the LMP less the generation component of retail rates. The corresponding wholesale-related savings received by the customer, paying a fixed retail rate, will be the generation component of retail rates.
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> From a wholesale power market perspective, the optimal payment under the Economic Program whether LMP is above or below the $75 per MWh threshold would be the LMP less the generation component of retail rates, because the generation component of retail rates is a substitute for the LMP If a customer is paying $40 per MWh for the generation component of energy in retail rates but by reducing load eliminates the need for the LSE to purchase a MWh at $900 per MWh, the total resource saving is $900 per MWh. The customer receives $40 per MWh of that saving by not paying the generation component of the retail rate and should receive the balance, $860 in this example, from the LSE payment.[14]

Thus, the payment of full LMP represents a subsidy to the demand resource and is a wealth transfer from one customer to another. Using the information provided above, the appropriate payment for LMP customers is zero as their benefit is not paying the market price of

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[14] *Id.* at 3-4.

energy and payment of LMP by customer is the goal of the program.[15]

ODEC wishes to raise an additional point to the IMM's statements. For discussion purposes, the IMM used an example where the LSE was paying LMP to serve the customers. As the Commission is well aware, wholesale providers of retail service predominantly use a bilateral portfolio approach in securing supply for load. The LMP price signal does not represent the wholesale supplier's cost to serve the customer. As indicated in the 2009 State of the Market Report for PJM, most energy is purchased outside of the PJM day-ahead and real-time markets. For example, in 2009, the annual average of day-ahead and real-time load served from the PJM spot market was 14.9% and 17%, respectively. All else was served via bilateral contracts and self supply.[16] Additionally, most LSEs utilize the day-ahead as opposed to the real-time market to address overages or underages based on short-term forecast error. ODEC uses this approach and our own generation to supply its members. Thus, the market price for LSEs, including ODEC, is the blended cost over this entire portfolio. This blended market price reflects the cost to the wholesale supplier of serving the customer and LMP is not an accurate signal because it does not reflect these and other components. Once there is sufficient de-

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[15] *Id.* at 7.

[16] 2009 State of the Market Report for PJM at 101-102.

mand elasticity at the local level, this "market price" will be provide a more accurate signal and should be used as the price to which load responds.

As previously stated, since PJM's current economic demand response program was created to address a market failure, it represents a temporary mechanism to provide a wholesale cost signal until such time as there is sufficient demand elasticity in place to allow real time response at the local level through the retail price structure. PJM's Market Monitor recognizes this in the 2009 State of the Market Report which states that:

> PJM's demand side programs, by design, provide a work around for end use customers that are not otherwise exposed to the incremental costs of energy and capacity. They should be understood as one relatively small part of a transition to a fully function demand side for its markets. The complete transition to a fully function demand side will require explicit agreement and coordination among the Commission, state public utility commissions and RTOs/ISOs.[17]

Although a workable alternative, the PJM demand response programs are temporary in nature, do not resolve all problems and will eventually need to sunset so that demand response programs at the local level

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[17] 2009 State of the Market Report for PJM at 103.

can develop. Some of the problems with the current program are:

- The LMP price signal only tells a customer when it may be beneficial to not consume energy. The customer is not provided guidance as to the best time to consume the deferred usage since the design of the program does not encourage participation in every hour; therefore an inefficient market outcome is expected. This is true because the customer can defer usage to another high priced hour, pay the retail rate and avoid paying the higher market price while having received compensation for the earlier reduction. Retail customers participating in the PJM program do not pay the wholesale market price so the PJM program allows a customer to reduce usage and receive compensation in the form of a payment of LMP minus G during periods of high prices or system reliability concerns.
- PJM has in the past two years implemented new measurement and verification rules to try to ensure that demand response reflects a reaction to price.[18] Although these changes have improved the process, manipulation may still occur as there is no way to know why a

[18] PJM Interconnection, L.L.C., Docket No. ER08-824 (April 14, 2008)

market participant reduces load and payments can be made for load reductions that would have occurred regardless of the prices in PJM's markets. These payments are an extra cost to all loads for actions that were not taken in response to market signals.

- Wholesale demand response programs are a work around until local programs are in place. Local programs will avoid the administrative costs of RTO and ISO programs and will prevent the need for measurement and verification rules that try to determine why a market participant is reducing consumption. In addition, cost-reflective retail rates can provide price signals that encourage retail customers to consume more during off-peak hours when energy is cheap to produce which solves the previously indicated problem with the LMP price signal that does not provide information of when to resume usage.

D. Demand response programs are more effectively implemented at the retail level

Except for the few end use customers directly receiving service at wholesale rates, demand response programs belong at the retail level. The wholesale programs focus the customer's attention on shaving the peak rather than on shaping usage and controlling energy usage which can lead to inefficient results.

Based on over 20 years of ODEC's member-owners' experience with local demand response programs, as

well as ODEC's direct experience in PJM, ODEC believes that demand response programs are more effectively and efficiently implemented at the local level. This is true for a number of reasons:

- The most effective and direct price signal for consumers is the retail rate based on the provider's cost to serve. Consumers can react to the price signal, reduce usage or implement energy efficiency and see the savings directly in their monthly electric bill without having to participate in another program. Providing additional compensation at the wholesale level will result in paying twice for the same action, cross subsidization of additional costs among all consumers and inefficient results as demand responders over-curtail if provided compensation above their economic costs.
- Demand response technology resides at the local level and is not a wholesale controlled function. ODEC's member-owners decide which demand response technology to install based on its cost of service and the needs of its customers.
- The EDC or local utility is in the best position to create demand response programs that fit into the EDC's supply portfolio and which meets its local needs.
- The EDC interacts directly with the consumer and is in the best position to educate the con-

sumer about energy efficiency actions and demand response programs.

- The EDC reads the meter and is in the best position to collect and verify data.
- States are imposing load reduction and renewable goals at the state or retail level. Programs implemented at the wholesale level may duplicate or impede these efforts.

While recognizing the role of the States in demand response, the Commission, through this NOPR, is proposing to impose a compensation mechanism on all organized markets which could have the unintended effect of impeding progress at the local level. First, by providing payment that is not reduced to reflect the avoided cost, G, the Commission is creating a subsidy which would not be present in retail demand response programs. This would lead to opposition by retail services providers of state programs that remove this subsidy. Second, with benefits derived from the programs at the wholesale level, it becomes less critical for states to make the difficult financial and political decisions necessary to put the metering infrastructure in place and to implement cost reflective rates.

An efficient wholesale market coupled with the proper local reactions to prices in that market will produce the economically efficient amount (the "right" amount) of elasticity of demand. Since additional infrastructure is needed to reach this goal which includes more transmission facilities at the wholesale

level and smarter grid at the retail level, ODEC can accept the concept that, until such time as demand elasticity is achieved at the local level, compensation for demand resources should be provided in the wholesale markets. However for the reasons articulated above, for this transitional approach, the appropriate compensation should be LMP minus G.

Although not a part of this proceeding, proper implementation of PJM's proposed price-responsive-demand or PRD would provide a transition to foster development of retail programs, appropriately place demand response on the demand side of the meter and recognizes that the wholesale markets need a mechanism to anticipate changes in energy usage as a result of price responsive demand at the retail level.[19] Through the PRD concept the PJM Management and Board recognized that demand response should be implemented at the local level and that the reduction in usage is an avoided cost to load. Terry Boston, the CEO of PJM, has acknowledged the superiority of cost reflective retail rates in facilitating economic demand response:

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[19] PJM's filing in EL09-68-000 which was dismissed as part of the Notice in this case established the concept of PRD which was defined in the filing as when end-use customers have the metering capability to record electricity consumption at an interval of one hour or less together with a retail rate structure that changes retail rates on a daily or hourly basis in response to locational marginal prices ("LMPs") or other conditions in the PJM Interchange Energy Market.

PJM's long-term vision is that "Price Responsive Demand", which allows more customers to respond directly to market prices and to voluntarily reduce their consumption when wholesale prices rise, is the ultimate solution to demand participation. These technologies, coupled with innovative retail rate structures will enable electricity users to see and voluntarily react to prices in an automated fashion.

Interruptible load implemented through retail tariffs and RTO Demand Response programs are the established first and second generation of demand response to markets. To continue this evolution, the next generation—price responsive demand—needs coordinated effort between PJM and States who oversee retail rates, as well as utility and curtailment services companies who have direct relationships with end use customers and can deploy these new technologies at the distribution level.

Therefore, the PJM Board of Managers seeks the assistance of State regulators to take advantage of price responsive demand capabilities through their own retail rate structure. To grow demand response and establish its participation as an enduring feature of PJM markets, our region needs innovative retail rates that are linked to wholesale prices. PJM's market is well suited to facilitate such demand participation because it already provides transparent price information at each location

that is consistent with grid reliability requirements.[20]

Good demand response is a function of the retail markets and should be designed, implemented and compensated at the local level. Once these local programs are implemented, then the wholesale demand response programs should sunset and compensation for retail customers should no longer be provided at the wholesale level. It is the role of the wholesale markets to get the price signals correct so that retail rate designs respond to the correct price signals.

III. RESPONSE TO THE SPECIFIC NOPR QUESTIONS

Whether current compensation for demand response providers acting as a resource in the organized wholesale energy markets is adequately procuring demand response.

Demand response in the organized wholesale energy market is a local reaction to wholesale prices and should not be considered a resource in the wholesale markets. At least in the PJM market, until retail rate structures are put in place that provide appropriate market signals based on the wholesale suppliers cost to serve, demand response treated as a resource may

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[20] Statement of Terry Boston on behalf of the PJM Board of Managers, June 26, 2009, p. 1. Available at: http://www.pjm.com/~/media/about-pjm/newsroom/2009-releases/20090626-pjm-board statement-regarding-dr-in-pjm-markets.ashx

be necessary as an interim measure to allow customers to have an albeit suboptimal experience that is loosely based on the concept of avoided cost through reduced consumption. As such, the current surrogate compensation of LMP minus G provides the compensation needed to promote demand elasticity in a manner similar to that provided by LMP-based customers. This procures a more economically efficient amount of demand response than paying full LMP because it is based on producing comparable net revenues and benefits for generation and demand resources as described earlier in these comments.

We further solicit comment on alternative approaches to compensating demand resources participating in organized wholesale energy markets and the merit of those approaches in comparison to the one proposed here.

As discussed above, ODEC believes that for PJM and perhaps other RTOs and ISOs, LMP minus G is the acceptable transitional compensation mechanism. This compensation enables a retail demand responder to experience the full value of avoiding the cost of wholesale supply. The Commission should allow RTOs and ISOs to determine the demand response programs and compensation that works best with their wholesale programs and the retail structures in their member states. Retail price structures, such as a Critical Peak Pricing, that provide price signals in the few hours during which demand response is desirable would provide the desired response from those able to

respond and any such response would depend on the consumers' desire to avoid higher prices. Retail rates need to be able to reflect the changing nature of wholesale costs of the local utility and local utilities need to have sufficient flexibility to send price signals to those actually able to respond. Until these local issues are resolved, sending price signals to those that are unable to respond will increase prices paid by consumers without generating the desired results.

Where local issues are being resolved, currently in very small isolated parts of the system, alternative approaches are probably desirable if they are designed to reflect in wholesale operations that which is occurring through more pure demand response. However, the appropriate alternative programs will be specific to each ISO and RTO and driven by various retail pricing structures as well as varying infrastructure. For instance, the PJM PRD program described in Section D above seems appropriate for PJM at this stage of its evolving demand response programs. Based on the uniqueness of each set of stakeholder needs, the Commission should allow RTOs and ISOs to determine which, if any, alternative demand response programs should be implemented.

In particular, we ask for comment on whether a reduction in consumption is comparable to an increase in electricity production for purposes of balancing supply and demand, and whether, therefore, demand response providers and generators should receive comparable compensation.

As described throughout these comments, a reduction in consumption is fundamentally different than an increase in production (*i.e.*, supply) due to issues such as demand elasticity roles, pricing forces, reliability characteristics, etc. Also, a reduction in consumption cannot purely be equivalent to an increase in production, because demand resources do not produce electricity as generation resources do, but rather demand resources free up generation resources to supply other loads. This concept is made apparent when considering a system with 50 MW of demand resources and 50 MW of load with zero generation resources. Obviously, there will be a blackout 100% of the time in such an extreme case.

Despite a reduction in electricity consumption not being equal to an increase in production, they are somewhat comparable in the sole function of balancing supply and demand. When supply and demand are at equilibrium and a 1 megawatt increase in supply is anticipated by the balancing authority, a 1 megawatt demand reduction would return the state to equilibrium. In such a circumstance, the comparable "compensation" to the demand resource is avoidance of the

wholesale cost which is approximated by LMP minus G as previously described.

Further, comparable compensation should also consider the reasons that short-term load reductions are not perceived as indicators of the long-term need for adding generation.

Some of the reasons for this are:

- Demand response disappears when prices drop while capital intensive generation remains and is dispatchable if needed.
- Demand response is a short term response to price and generation is a long term response to need.
- One MW of generation can improve the reliability of grid, but one MW of demand response can only displace a supply resource in the short-term.

Put another way, we cannot light our homes with demand response. However, demand response has an economic impact and value as it affects where supply and demand intersect, but it is not comparable to generation.

As previously indicated, ODEC supports compensation for demand response resources of LMP minus G until such time as sufficient infrastructure and retail rates are in place at the local level. When this occurs, the wholesale programs would sunset and demand responders would be able to react to the particular

wholesale supplier's portfolio-based market price. Demand resources should not receive payment of full LMP, because it provides an added subsidy and results in over-compensation with a net benefit to the demand resource of LMP plus G, based on an avoided cost of consuming of G plus payment of LMP from PJM.

We further seek comment on whether paying LMP to demand response resources is comparable compensation or is more or less than comparable to compensation paid to generation in the ISO and RTO energy markets.

Demand responders receive compensation in the form of avoided energy costs and should not receive additional compensation. Where demand responders do not have rates that are reflective of their suppliers' time-varying and locational costs, a wholesale demand resource program may be temporarily appropriate where such program is designed to mimic the "would-be" avoided costs under the aforementioned type of local program. Under such interim demand resource program, the mimicked avoided cost is roughly LMP minus the actual avoided payment of the local supplier's generation (G) component of their rate, as more fully described earlier in Section IV.B. of these comments. Paying full LMP to demand resources is over-compensation and results in a wealth transfer between load groups.

We also request comment on whether payment of LMP should apply to all hours, and, if not, the criteria that should be used for establishing the hours when LMP should apply.

For the reasons discussed in these comments, full LMP should not be paid to demand response in PJM in any hour. The acceptable interim compensation until sufficient retail programs are in place is LMP minus G in all hours in which there is a curtailment in response to price.

Additionally, we seek comment on whether requiring payment of LMP is appropriate across all ISOs and RTOs, or whether variations among ISOs and RTOs justify varying levels of demand response resource compensation. To that end, we further seek comment on whether the Commission should allow regional variations for an ISO or RTO that does not seek to compensate demand response resources participating in the organized wholesale energy market.

While LMP minus G is the acceptable transition compensation in PJM, the Commission should allow each RTO and ISO to work with stakeholders to develop and implement the compensation mechanism that works best for them. Allowing stakeholders to consider whether or not to allow participation of demand response as an artificial resource in their wholesale market is appropriate. As previously indicated, ODEC does not believe that payment of full LMP to demand responders is appropriate in PJM.

We also seek comment on whether, and under what circumstances, the Commission should conduct periodic reviews of demand response compensation and the criteria that should be used in making such assessments.

The Commission should allow RTOs and ISOs to propose the demand response compensation mechanisms that are supported by their stakeholders or independent boards and condition approval of such mechanisms on market monitoring oversight. Additionally, if such programs treat demand response as a resource, those programs must not be discriminatory or preferential toward other types of resources. The Commission should determine whether such programs result in just and reasonable rates on many bases, including whether the programs continue toward market efficiency and least-cost service for customers.

With specific regard to the proposed regulatory text set forth below, we seek whether terms such as "expected levels," "price signals" and "market prices" are sufficiently defined.

§ 35.28 Non-discriminatory open access transmission tariff.

(v) Demand response compensation in energy markets. Each Commission-approved independent system operator or regional transmission organization that has a tariff provision permitting demand response resources to participate as a resource in the energy market by reducing consumption of electric energy from their expected levels in

response to price signals must pay to those demand response providers, in all hours, the market price for energy for these reductions.

For the reasons discussed in these Comments, ODEC does not support mandating a single compensation mechanism for all RTOs and ISOs, and LMP minus G is a workable yet suboptimal interim compensation for at least PJM to use until such time as sufficient demand response is available from retail programs. Consistent with ODEC's position, each RTO or ISO should determine and set forth in its tariff how it will quantify the "expected levels." ODEC believes that "market price" and "price signals" are sufficiently understood such that they need no further definition, although ODEC does not agree with the Commission's proposed compensation structure.

IV. CONCLUSION

ODEC appreciates the opportunity to submit comments on this important issue and urges the Commission to allow RTOs and ISOs to address this issue through the stakeholder process until such time as there is sufficient demand elasticity on the local level as a result of dynamic pricing and new technology to allow consumers to respond to real time prices.

Respectfully Submitted,

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Dated: May 14, 2010

UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. RM10-17-000

DEMAND RESPONSE COMPENSATION IN ORGANIZED
WHOLESALE ENERGY MARKETS

REPLY COMMENTS OF VIRIDITY ENERGY, INC.

Introduction

Viridity Energy files these Reply Comments[1] and the attached reply statements of Audrey Zibelman and John Tysseling to respond to assertions by some commenters that payment of full Locational Marginal Price ("LMP") for demand response resources is inappropriate and to respond to the differences in focus and mode of analysis between supporters and opponents of the proposed rule.

In the proposed rulemaking, the Commission provides the RTO/ISO's the opportunity to continue to serve as a vehicle for creating the competitive, efficient and sustainable markets that support continued innovation, and the development of truly "smart" power

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[1] Viridity acknowledges that the Commission did not expressly allow or disallow Reply Comments in this proceeding. To the extent necessary, Viridity seeks leave to reply and have these Reply Comments considered by the Commission.

grids and markets. Supporters of the proposed rule identify the substantial and concrete real world benefits that increased participation of price responsive load will bring about in operation of the electric markets. Supporters of the rule have cited the increased competitiveness of the markets; increased elasticity of demand; the reduced concentration of market shares and the concomitant mitigation of market power; the reduction in line losses; the reduction in clearing prices and enhanced reliability, all of which will accrue to customers if demand response is fairly compensated.

Opponents of the proposed rule do not deny that these benefits exist. Rather, they offer outdated views on the relative value of controllable load and supply on the grid, proffer theoretical concerns about the relative consumption of electricity vis a vis other products in the economy, and assert internally inconsistent and specious jurisdictional arguments. It is respectfully suggested that the Commission should focus its attention on the very real improvements in market operation that increased demand response will create and should therefore adopt the proposed rule.

The purpose of these Reply Comments is to respond to particular misconceptions about the nature of proactively managed load and its benefits to the markets and to the internal inconsistencies in the opponent's jurisdictional claims. Specifically, in its reply comments Viridity focuses on the following arguments that the opponents of the rulemaking rely on to argue against the Commission's proposal to provide compa-

rable treatment to actively managed load in the FERC jurisdictional wholesale power markets:

1. The Opponents' arguments ignore bid based security constrained economic dispatch as the foundation for locational marginal pricing and reflect outdated and erroneous perceptions on the nature of proactively managed load control in a 21st Century electric industry;

2. The Opponent's economic claims are based on selective and unlikely scenarios of consumer decision making;

3. The Opponent's jurisdictional and legal arguments are internally inconsistent and incorrect;

4. The need for certain specific market design rules to address cost allocation and, if necessary, measurement and verification, can be dealt with by the RTO/ISO's as needed and should not detract or delay the current rulemaking;

5. Opponents of the proposed rule raise unsubstantiated concerns regarding service reliability; and

6. Opponents of the proposed rule cite potential inappropriate behaviors but fail to acknowledge FERC's on-going authority to address

market developments as they arise (should the concerns actually materialize.

The opponents of the proposed rule ignore several basic truths:

> Controlled load is a service rendered to the grid (and to other customers) by customers who are able to manage their consumption. And that service is rendered in the wholesale market—where the value of the service is LMP.

> The wholesale transaction involved when this service is provided is wholly separate from the retail transaction in which the customer purchases his supply. There are two separate transactions here—and the LMP-G formulation favored by opponents of the rule blurs important jurisdictional boundaries—and intrudes on retail ratemaking issues.

> The proposed rule furthers the Commission's efforts to maintain just and reasonable rates. This represents an appropriate allocation of benefits between customers and suppliers under the Federal Power Act.

Opponents of the proposed rule assert that if customers were exposed to dynamic real time LMPs the result would be economically efficient allocation of resources and that no compensation for demand response service would be appropriate. The ideal world envisioned in these comments is at odds with reality. Imperfect markets, both for electricity and the products which vie with electricity for consumer dollars,

are a fact. There is no proof on the record of this proceeding that the prices of electricity or of competing products are welfare maximizing—or are the product themselves of inputs delivered in perfectly competitive markets. The arguments that LMP compensation to demand response service will disrupt an otherwise economically efficient allocation ring hollow in the real world.[2]

I. The Opponents' arguments ignore bid based security constrained economic dispatch as the foundation for locational marginal pricing—and reflect outdated and erroneous perceptions on the nature of proactively managed load control in a 21st Century electric industry.

A fundamental flaw that underlies all of the opponents' commentary is their inaccurate and backward looking view of the capabilities and service that load based energy resources can offer the market. While many commentators embrace the value of what the industry terms demand response, they wish to restrain the participation of demand to a traditional "peak shaving" or an emergency role in the competitive market place.[3] Fortunately, the proposed compensation rule adopts an accurate 21st Century view of how competitive markets can offer comparable and non-discriminatory treatment of load based energy resources.

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[2] Tysseling Affidavit at 3-4, 19.

[3] See for example EPSA's Comments at 12 suggesting that capacity market revenue should be sufficient for demand response.

All commentators agree that we must maintain a reliable electric system and must keep the grid in balance. Nor is there any serious dispute that from an electrical perspective the balance can be achieved by either incrementing power output or decrementing power consumption in real time. Despite agreeing with these fundamental factual precepts, opponents of the proposed rule base much of their argument on two basic misconceptions: A) Opponents erroneously equate the economic concept of supply to the use of grid based supply resources; and B) Opponents constrain themselves to a vision that artificially limits consumer participation in the energy market to traditional "peak shaving".[4] While both of these perceptions may have been appropriate fifteen years ago, evolution of the wholesale power markets and technology render them no longer accurate.[5]

A. The traditional economic definitions of supply and demand are not synonymous with grid based generation and load on the interconnected power grid in markets that use bid based security constrained economic dispatch.

One of the more confounding aspects of this debate has been that the industry uses the language convention of "balancing supply and demand" as shorthand for bid based security constrained economic dispatch, the actual practice used by the operators to maintain

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[4] *Id.*

[5] Zibelman at 3.

grid balance. The manner in which grid operators implement this form of dispatch has evolved over time as the markets have evolved. This proposed rulemaking is a further evolution of how the wholesale markets should achieve balance. The rulemaking uses this bid based security constrained economic dispatch to assure that the markets remain unbiased and efficient, and thereby produce "just and reasonable" rates. Rather than acknowledging the bid based regime, opponents of the rule reference the costs, instead of the bids, associated with some active load management processes.[6] As the Commission is aware, the LMP regime that generators and other market participants operate under is based upon a bid based clearing mechanism, not a cost based inquiry.

Prior to the development of markets, vertically integrated regulated utilities used security constrained cost based economic dispatch to manage dispatch of their owned generation resources. Utilities bought and sold power among themselves over pancaked transmission tariffs that used arcane formulas to calculate available physical transfer capacity. While simple, this world was self-limiting and more often than not lack of real time information and the absence of impartial and independent grid operators artificially constrained the actual capabilities of the integrated system. Within this simpler world the simple convention of equating the economic terms 'supply' to

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[6] *See* EPSA at 52 for example.

generation and 'demand' to load may have been appropriate.[7]

However, the development of independent grid operators, and new markets and technology, have fundamentally changed how we manage the integrated electric system. The mechanisms used by independent grid operators to perform bid based security constrained dispatch also have changed. First, the concept of supply and demand in the market is not limited to physical generation and physical demand located within the physical control area under the responsibility of the control area operator. Rather, operators will include energy imported as supply and energy exported as demand. In addition, generation resources now include not only fuel based dispatchable combustion resources, but non-dispatchable variable resources such as wind and solar, and controllable storage. When calculating bid based security constrained dispatch, operators must now forecast and account for the fact that when non-dispatchable resources reduce their output, the operator must have sufficient resources under its control to retain a grid in balance.

Further, and most critical for the current rulemaking, usage on the grid now consists of both fixed or inelastic levels of load—and load that can be predicted

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[7] The equation of "supply =generation" can be seen in Exelon's comment that "Just as a generator must first generate electricity before it can sell it, DR must first purchase electricity before it can sell it." Exelon at 6.

and dynamically managed in accordance with price or physical requirements. Within the context of bid based security constrained dispatch, it is no longer accurate and, is, in fact, misleading to equate grid based generation with "supply" and behind the meter load with "demand" when describing the real time process of keeping the grid in balance. Rather, a current definition would be to acknowledge that when achieving an efficient market using this accepted form of dispatch, the term "supply" should mean the resources that can be increased or decreased to keep the load in balance and demand refers to the resources that do not possess this capability.[8] In this characterization, "supply" refers equally to scheduled imports, dispatchable generation, storage devices and actively managed and controllable load—and "demand" means the intermittent generation and non-flexible or fixed load that are non-responsive to price or operator control.[9]

Public policy should recognize that fair, non-discriminatory markets must adapt and eliminate barriers to the entry of non-traditional resources in the dispatch and management of the system. The non-traditional resources that must be embraced include wind and solar plants, storage facilities, and actively managed demand. In a bid based security constrained dispatch regime, the grid and/or market

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[8] Tysseling at 9.

[9] Zibelman at 5-6.

operator has the ability to identify and rely on the very next lowest priced resource, whether that be increasing generation or decreasing load.

In a wholesale market where LMP reflects the highest priced bid accepted to achieve grid balance, the fundamental rules of using a single clearing price, comparability and non-discriminatory treatment, require the same level of LMP compensation for any resource that is dispatched. All resources should get paid LMP if the grid operator accepts their bid to achieve grid balance.[10] In the context of security constrained bid based economic dispatch, an accurate definition of "supply" is the resources (of whatever stripe) that the grid operator deploys to achieve a balanced network. When a consumer bids to achieve balance through an accepted and demonstrable price responsive reduction in the amount of demand it places on the grid, it is providing a "supply" service to the grid and accordingly must be compensated at the prevailing LMP

B. The Opponent's Argwnents Reflect a Constrained and Artificial View on the Role of Actively Managed Load on the Power Grid

A second fundamental flaw in the Opponent's arguments is the fact that they misrepresent the current state of technology and investments that consumers use to participate as a controllable resource in the

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[10] Tysseling at 11.

wholesale power markets.[11] Many opponents propose that the value of load management on the grid is limited to periods when the system is stressed, i.e. traditional "super peak shaving" They also argue that increased levels of demand response participation in the market will result in increased levels of needed generation and transmission because of "reliability" concerns.[12] We disagree.

The arguments reveal very different visions of a market that takes full advantage of a smarter grid. The vision that the proposed compensation rule suggests is a digitized two-way grid that is able to use centrally dispatched generation resources, distributed resources, storage and active load control as mechanisms to maintain service reliability and security in all hours of the day. Contrary to the assertions of the Opponents, the availability of actively controlled load does not compromise system reliability or require increased investment in generation or transmission.[13] Instead, when load can be predicted and controlled in response to price, system reliability and efficiency is increased because the system operator can rely on actively managed load as a resource that can retain

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[11] *See* EPSAs comment at 25 that the real barrier to demand response is the lack of retail real-time metering as opposed to, for example, the need to compensate the customer for his investment in demand response capability.

[12] *See* Comments of PJM Power Providers at 37 and Tranen Affidavit at 7.

[13] *Id.*

system balance. Moreover, customer owned energy resources will reduce transmission losses on the system, defer the need for new transmission, produce reactive power, provide regulation service, and help distribution utilities manage loading on individual circuits.[14]

Given increased investment in intermittent generation resources and public opposition to transmission and distribution plant investment, dynamically controlled load represents another arrow in the grid operator's quiver to enhance operating reliability and grid efficiency.

There are many early morning and nighttime hours where there are segments of the grid that could use additional demand to avoid min-generation conditions or "negative" LMPs. An opportunity exists in the ability of load to increase consumption during those "valley" hours, such as by charging storage. In order for this to occur, load must have the means to invest in storage, control systems and/or distributed generation. One of the underlying benefits of the proposed rule is the recognition that with the ability to actively participate in the wholesale markets, the amount of fixed peak load on the grid will be flattened and controllable load can be used to fill in usage valleys.

The efficiency gain is clear—a better load factor. The suggestion by EPSA and P3 that fair compensa-

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[14] Zibelman at 9.

tion of load will reduce reliability is troubling. It is not that long ago that independent generators were thwarted in their attempts to create an industry because utilities exacted onerous and time consuming interconnection and operating requirements under the guise of reliability. It took the FERC's intervention to eliminate these barriers. The creation of independent competitive markets is the result. Indeed, within these markets, generators fought for and achieved the right to retire units largely at will, despite the effect their retirement would have on system reliability. It is remarkable that these self same participants are using threats of reliability to retain artificial barriers to load's participation in energy markets.

Many load participants or their representatives in the markets either have invested or are desirous of investing in advanced control systems, storage resources and renewable and dispatchable generation that can be used to manage load on the system. The economic decision that the customer uses to dispatch these resources is complex and requires algorythmic based calculations, system understanding and contingency analysis to produce the desired economic outcome.[15]

The simple example of a generator being moved behind the meter that Professor Hogan and others offer to suggest that active demand participation in the market will result in consumers making uneconomic

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[15] Tysseling at 9, 13.

and inefficient decisions is unrealistic and highly selective. Generators bid into the market today at a price lower than LMP for a number of reasons. For example, the generator may have a minimum run time and perceive that prices will be increasing over the course of the day. Second, the generator may be contemplating a maintenance outage and/or have a certain amount of fuel to burn to avoid penalties. Third, a generator may voluntarily submit a bid to run out of merit order so as to cure a restraint on the system. All of these are perfectly reasonable and, on an overall basis, economically sensible reasons for the generator to bid as he does.[16]

In the case of a generator behind the meter, the decision to dispatch when the cost is higher than the LMP may be for all of the reasons stated above and then some. The participant may perceive that by offering the generator onto the grid as a means of reducing demand within the zone, its total portfolio value is increased notwithstanding the loss that will be caused by an LMP payment lower than the generator dispatch costs. In a system that uses bid based dispatch as opposed to cost based dispatch, this decision making process reflects a rational economic decision for the individual participant and is no different than a generator choosing to bid at a price that is lower than its economic costs for the reasons stated above. In a system that uses bid based, as opposed to cost based,

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[16] Zibelman at 11.

security constrained dispatch, in the absence of market power, the FERC's and the RTO's inquiry, should go no further than determining that the incremental resource offers the desired service—a balanced grid.

The Commission should disregard the hypothetical assertions that the outcome of this ruling will result in a race by consumers to move generators from in front of to behind the meter.[17] For the purpose of assuring grid reliability the location of a generator behind or in front of a meter is an irrelevant issue. Based on current environmental and renewable policies in the various states, it is more likely than not that any new resources that consumers invest in to control demand will be renewable or gas fired generation, storage in various forms and advanced load control systems. These type of investments are contemplated and desired in the smart grid and encouraged by renewable polices. In short, the assertions that the proposed rule will have an unintended and negative impact on the grid are based on suppositions that are selective, artificial and incomplete.[18]

II. LMP Is The Value In The Wholesale Market Of The Next Increment Of Supply Or Decrement Of Load.

Opponents of the proposed rule have suggested that compensation be set at LMP minus the generation

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[17] See Hogan at 6.

[18] Tysseling at 13-14.

portion of the retail rate.[19] These parties do not deny that LMP reflects the wholesale value of the service provided. Rather, they seek to draw the Commission into a review of retail rate matters beyond the Commission's jurisdiction. There are multiple flaws in this approach.

Demand response is a service provided by some customers to other customers in the wholesale market. The value of that service in the wholesale market is LMP.[20] The LMP-G formulation does not provide compensation equal to the wholesale value. Moreover, it discriminates against a class of service based upon the identity of the service provider (in this instance a customer.)

Some commenters suggest that payment of LMP to controllable load constitutes compensation greater than that paid to generation. These parties reach this conclusion by treating the cost avoided by the customer by not consuming as 'compensation'.[21] This characterization is erroneous because an avoided cost is not compensation. The customer forgoes the value of the electricity and avoids the cost thereof; the slate is clean; there is no compensation.

The suggestion that the wholesale rate should reflect retail rate structures is fraught with other diffi-

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[19] See PPL at 12.

[20] Tysseling at 18.

[21] See P3 at 5.

culties. It is not possible to know with any certainty what the generation portion of a retail rate actually is. Retail contracts do not tend to break the rate down into generation, transmission, distribution, overhead, and other components. They simply set forth a rate in cents/kwh. The definition of what the 'G' component is, is often provided by the LSE, a party with an interest in the calculation. Moreover, different retail contracts will reflect different generation costs depending upon the vintage of the contract. Retail contracts entered into in the wake of Hurricane Katrina will reflect quite different costs than those entered into three years later. Therefore, any attempt to reflect a "G" component will be wrong for many customers.

Rather than tailoring a wholesale rate to retail rate conditions, as these commenters suggest, it is far more sensible to get the wholesale rate right in the first instance and then let retail rate structures adjust as needed to wholesale market conditions. This is so because retailers purchase in the wholesale market the power they re-sell at retail. Thus, the retail rates they offer will adjust to and reflect the wholesale market conditions they encounter.

Also, retail rate structures reflect a wide range of competing considerations that State Commissions weigh when setting rates. Among these rate design considerations are an attempt to reflect cost causation, a desire to avoid rate shock, an interest in gradual reallocations of cost if necessary, the impact of rate

design on employment and the state of the local economy, etc etc. All of these policy considerations are appropriately left to the discretion of the State Commission. The Federal Commission should establish a compensation rate that reflects the value of the wholesale service provided by the demand responder rather than a rate that may reflect a myriad of local concerns.[22]

Customers providing demand response service engage in two separate transactions in two separate markets. The customers are selling a service to the wholesale market; the price of which is determined by the Commission's wholesale market rules as LMP Second, the customers are buying power at retail at competitively determined or state mandated retail rates. These are separate transactions and should be viewed as such. If the distinction between these two transactions is kept in mind, the proposal to set wholesale compensation to reflect retail conditions is seen as problematic; as is the suggestion that customers must buy the 'commodity' in order to sell the 'service.'

The position expressed by the California Investor Owned Utilities and California ISO is consistent with the preferred approach.[23] The IOUs support the

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[22] Tysseling at 7.

[23] See Comments of San Diego Gas & Electric Company, Southern California Edison Company, and Pacific Gas and Electric Company, at 2; Comments of California ISO.

proposed rule, and urge the Commission to maintain a clear demarcation between wholesale and retail markets, and not mandate in FERC tariffs the administration of retail revenue compensation associated with the participation of DR resources in wholesale markets. This position requires the Commission to set the wholesale compensation rate at the value of the service to the wholesale market and allows the State authorities to exercise their jurisdiction over local matters.

If a State were to conclude that payment of LMP was actually imposing costs on the general body of ratepayers rather than benefitting them, the State could address the issue through its jurisdictional powers. The scenario is unlikely to occur because it implies large amounts of demand response (hence a cost) coupled with little or no effect of demand response upon LMP; nonetheless, if such a scenario is worrisome a State can address it.

III. When Properly Defined, Demand Response Is Understood as Active Load Management Undertaken in Response to Price.

Opponents of the Commission's proposed rule have developed a number of hypotheticals to illustrate potentially uneconomic or inappropriate behaviors that the rule might spark. In most cases, these hypotheticals are based upon a definition of demand response that is not consistent with the underlying logic of the proposed rule itself—to compensate active load management taken in response to electricity prices. For example, Professor Hogan posits an example where a

generator is moved behind the meter and is then run flat out, with no particular response to price, simply because the payment of LMP allegedly subsidizes the operation.[24]

This is not an example of active load management or demand response. A behind the meter unit that runs flat out is not engaging in a load management strategy. It is not price responsive. And if such a unit is filing settlements for demand response the RTO should investigate the matter. But the market rules developed by the Commission should not be fashioned to respond to extreme, selective hypotheticals.

This is just one, highly selective example. A more realistic example, where distributed generation is part of an active load management strategy, is where a behind the meter unit is run periodically in aid of the overall load management program, such as to charge a battery, which will be dispatched later in the day. Or where the distributed generation has a minimum run time and some of the hours may occur "at LMPs less than operating cost" but other (adjacent) hours are economic.

In the 21st Century customers will employ a variety of techniques to manage their electricity consumption and their electric bills. Demand response is properly defined as part of an active load management

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[24] Implications for Consumers of the NOPRs Proposal to Pay the LMP for All Demand Response, at 7.

strategy.[25] The strategy can include load shifting in response to price or dispatch of behind the meter resources in response to price as part of the active load management strategy. The result of active load management is load shaping; managed usage; a more efficient operation.

In the new world of smart grid, intelligence is moving to the edge of the grid; to the customer premises. The Commission must accommodate the new paradigm and set rules that allow the micro-grid to interact with the macro grid in mutually advantageous ways. The rules should not reflect unlikely hypothetical situations.

IV. The Purpose of Wholesale Demand Response Compensation Is Not to Force Customers Onto Real Time Pricing Arrangements.

The comments by several parties assert that if customers were served at prices that equaled the real time LMP that demand response compensation would be rendered unnecessary.[26] This perspective ignores the differences between the purposes served by operation of the bilateral, real time and day ahead markets. Customers do not uniformly want to be exposed to volatile real time prices. Many customers actively seek hedges against volatility and against the uncertainty of real time prices. It would not be a good policy choice

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[25] Tysseling at 14.

[26] See PPL Comments at 5.

to restrict customer's efforts to hedge themselves. Information about real time prices is imperfect at best and customers seek hedges either in the form of long term contracts or through day ahead purchases. Similarly, a customer that makes a day ahead curtailment offer seeks to insure itself of a known and certain price for its curtailment service. And if the day ahead offer clears, the grid operator and affected LSEs will have notice of the scheduled operations and expected level of curtailment from the customer. And the appropriate quantity of both demand response and supply can be scheduled. If the customer fails to deliver the curtailment and deviates from the day ahead commitment, the deviation would of course be charged the real time price. But there is no need to charge the real time price for all consumption.

Demand Response in the real time market may operate differently. Demand response in the real time markets will involve minimal notice to the grid operator depending upon the specifics of each RTOs bidding regime. Under the circumstances, an appropriate market rule for real time demand response offers will require demand responders to assume the risk that their curtailments may or not be compensated. For example, a demand responder will make an offer in the real time market but will not know until after the fact whether or not its offer was cleared. Thus, if the customer chooses to curtail in real time it will do so at its own risk and will only discover after the fact if its curtailment cleared and was compensable.

V. Increased Levels of Demand Response Do Not Threaten Reliability.

Several commenters note the effect that demand response will have in terms of reducing LMP and then assert that this market result threatens reliability.[27] At the same time the commenters make this assertion, they also note with approval the increased participation in the capacity markets. We respectfully suggest that the increased participation in the capacity markets is an example of demand response enhancing reliability.[28]

The assertion that reduced LMPs attributable to demand response threaten reliability by unduly reducing generator earnings is peculiar. The reduction in LMPs will be the result of a competitive market mechanism previously endorsed by the Commission and many market participants. Prices rise and prices fall in response to fundamental market conditions. Second, demand response will reduce load and will reduce the need for construction of new infrastructure. Demand response in the capacity markets has had this impact—and demand response in the energy markets will extend this effect. The reduction in the need for new infrastructure is an important social benefit that

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[27] See EPSA at 42; PJM Power Providers at 3.

[28] During the 2009/2010 Delivery Year, demand side resources in PJM performed at 118% of their committed capacity values during PJM testing. Concerns about performance should be laid to rest.

does not figure in the complaints regarding reduced LMPs.

Opponents of the proposed rule have asserted that demand response is a purely voluntary service that cannot be relied upon for operational security purposes in the same manner that dispatchable generation can. They characterize it as an inferior product.[29] This characterization as 'purely voluntary' and inferior is not accurate. For example, demand response that bids in the day ahead market, and clears, has the same reliability characteristics as dispatchable generation. Comments such as these tend to obscure the basic fact that load is now a controllable, flexible, and dispatchable resource that can be relied upon for maintaining balance. Moreover, as time passes a representative amount of demand response can and should be included in RTO planning processes, based on historic, empirical data.

VI. Payment of LMP to Demand Response Will Not Incent Inefficient Behavior When One Considers a Longer Term Operating Schedule And the Complexity of The Customer's Operations.

Several commenters offer simplistic examples to demonstrate that payment of LMP will incent customers to dispatch uneconomic generation.[30] Of course, it

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[29] See P3, at 3.

[30] See for example, Exelon, at 9-10.

is possible to devise such scenarios but the reality of the situation is that a customer's decision making process is much more complex than reflected in these simple examples.

A customer with multiple resources at its disposal (a gas generator, a storage device, and controllable load) will seek to optimize its use of all these resources —and will plan its market participation days in advance and will signal its participation through day ahead bidding. Importantly, the schedule the customer develops will reflect its operations over a longer time period than the single hour reflected in the comments submitted by some parties. For example, part of a customer's long term planning for next-day operations may include increasing consumption during low load, low LMP night time hours for the purpose of charging a storage device.[31] The customer will do so for the purpose of discharging the battery several hours later when the cost of power is higher. This is a rational, economic course of action which reflects the customer's evaluation of costs and operating choices over the course of a day. The customer's decision will be reflected in its day ahead scheduling which will include night time purchases and mid-day curtailments made possible because of the prior purchases.

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[31] From society's perspective, the filling in of a usage valley is efficient and is certainly a better solution to low-load conditions than employment of negative LMPs.

The customer seeks to optimize its operations over a 24-hour period. Its decisions will reflect the myriad of operational and economic constraints (generation attributes, purchase of grid power, etc) of a customer with multiple resources at its disposal. The schedule adopted by a customer illustrates the complexity of the customer's decision making and also the fact that the planning reflects a far longer period than the single hour suggested by commenters. The customer may pre-cool a building so as to later control consumption when prices are higher. The 24 hour planning period reflects an optimized, economic decision by the customer which minimizes its costs over the longer period.

The situation is far more complex than the simple scenarios devised by opponents of the rule. Indeed, the situation will be even more complex than the increased night time usage and reduced day time load, associated with storage, noted above. Many customers will have both storage devices and generation resources, such as gas fired generation, at their disposal. In an effort to manage its portfolio and minimize its power costs, the customer will attempt to use all of its resources in the most effective means possible. The customer may predict six hours of high LMPs on the following day but it only has two hours of storage discharge capability. Moreover, the customer's generating unit may have minimum run requirements similar to those of supply side generators. Therefore, the customer will, through its day ahead bidding, plan on running its storage for its full two hour capability and

also running its generator. The generator may have, by way of example, a four hour minimum run time, and the unit's cost may exceed the LMP for one or two of those hours. Opponents of the proposed rule will point to those two hours and assert that uneconomic decisions are being made. However, they fail to note two important factors: 1) security constrained economic dispatch accommodates minimum run times of supply side generation and comparable treatment would acknowledge the same for customer owned generation and 2) when one examines the entirety of the situation the customer has behaved economically in that its storage was dispatched economically as was its generation, when generating unit constraints, such as minimum run times, are acknowledged.

Dispatch of customer owned generation will enhance social welfare in many scenarios not plotted out by opponents of the rule. For example, a given customer may have 100 Mw of fixed load and 50 Mw of variable load, which can be run depending on price. A manufacturer who runs two work shifts per day routinely but who can run a third shift, if prices are low enough, is an example. If another customer, one with controllable load or dispatchable generation, offers its service to the market it may reduce LMP such that the other customer can now run its third shift. The enhanced production by the consuming customer (and all of its multiplier effects) reflect net social welfare gains.

The decisions made by the customer are efficient when costs are measured over the longer time horizon

used by the customer for decision making. Moreover, the conclusion reached by opponents of the proposed rule that the customer will act inefficiently are incorrect because they exclude from their analysis many relevant costs. Customer curtailment, or dispatch of distributed generation, brings cost savings in the form of avoided transmission investment, avoided distribution investment, and avoided generation construction. These savings are not reflected in the examples offered by opponents of the rule but it is clear that they exist. Indeed, it would be inefficient to forgo compensation to demand response and to thereby force these investments to be made when they could have been avoided.

VII. Public Utilities Do Not Have a Right to A Particular Rate Level.

Several parties assert that the reduction of LMPs by enhanced demand response participation in the markets will deprive utilities of their statutory and constitutional right to just and reasonable rates.[32] The assertion is meritless. The Commission relies upon competitive market mechanisms to assure that rates are just and reasonable, both for customers and suppliers. The increased competitiveness of the markets associated with enhanced demand response may well reduce prices but it does not violate any statutory or constitutional standards. It is the result of a market process. The citation to Hope Natural Gas by

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[32] See EPSA at 40.

EPSA is particularly misplaced. The concept of establishing a fair rate of return is associated with cost of service regulation. In the market based regime employed by the Commission, fundamental competitive market conditions determine the return earned by market participants—not administratively set rates.

If a market participant with market based rates authority feels aggrieved by market results it has the right to petition for a cost based rate in lieu thereof. To date, we know of no entity with market based rate authority which has availed itself of this right.

VIII. The Focus Placed on the Cost Incurred By Particular Demand Responders Is Inconsistent with the Treatment of Supply Side Resources.

Several commenters assert that the proposed rule will lead to dispatch of demand response when its cost exceeds the market clearing price.[33] This focus on the cost of the individual demand response supplier is discriminatory. The Commission and the RTOs do not focus on the cost of a particular generator when it submits an offer. Nor is a comparison made between the generator's costs and the ultimate clearing price. For example, when a generator self schedules it receives the clearing price without any inquiry into its actual costs. Its costs may or may not have exceeded the actually determined clearing price. And its dis-

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[33] See for example, Electric Power Supply Association, at 52-53.

patch may or may not turn out to have been out of merit. The Commission employs bid based dispatch, not cost based dispatch.

The focus on the demand responders costs (or return) is discriminatory in a second respect as well. The Commission relies upon competitive forces to insure the maintenance of just and reasonable rates. It does not engage in cost of service regulation for generation resources. Yet the focus on calculating the return to demand responders is an exercise in cost of service regulation for this class of service providers. It is unduly discriminatory to set compensation for the supply side based on market mechanisms but to impose cost of service regulation on other market participants.

IX. Demand Response Compensation Does Not Require Customers to Buy and Then Resell Electricity.

Several parties suggest that payment of LMP compensation should be conditioned upon a customer contracting for a fixed quantity of MWhs which the customer can then sell back if the customer chooses to curtail its consumption.[34] There are multiple problems raised by this suggestion. First, the suggestion intrudes upon State responsibilities by tying wholesale compensation to a required retail rate structure. Second, this sort of requirement will act as a major

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[34] See Exelon at 6.

dis-incentive to demand response. The type of contract being suggested is not common in the retail market place. Customers do not want to incur take or pay obligations. Therefore, if the Commission adopts the proposal and conditions payment of LMP upon a take or pay retail rate structure, the result will be very little or no demand response, because retail customers will not sign these types of contracts. Third, the suggestion requires that demand response be characterized as a purchase and then resale of electricity. The Commission has specifically rejected this approach. The Commission has ruled that demand response is a practice subject to Commission jurisdiction; it is not a resale of electricity. Finally, the idea that the Commission would dictate the type of contract that customers must enter into in order to provide demand response service is antithetical to the very idea of a market. Rather than an administratively determined contract structure, development of the markets will be advanced if the Commission adopts appropriate wholesale market rules and then allows market participants to develop contracts that respond to those rules.

X. Enhanced Demand Response Will Further the Commission's Efforts to Establish Just and Reasonable Rates.

In many respects the different positions presented to the Commission simply reflect a choice to focus or highlight different factors. Opponents of the proposed rule highlight the potential returns to the par-

ticular customers who provide the demand response service. Opponents of the proposed rule focus upon the customer's bill savings, and then suggest that curtailment is 'uneconomic' in certain instances. This sort of micro-analysis is inapposite and discriminatory. The Commission does not inquire into the specific earnings of supply side resources. Nor does the Commission inquire into the cost of specific generating units except in rare instances.

The opponents of the NOPR ignore or discount the important and positive effects of demand response upon RTO operations and upon market structure. The Commission's focus of attention should be on the macro effects of demand response on the grid. Specifically, demand response can enhance grid reliability and reduce clearing prices. Demand response can reduce concentration of ownership in the market. These attributes of demand response are beneficial to all customers and further the Commission's statutory mandate to insure reliable service at just and reasonable rates. These macro benefits, which are concrete, historically verifiable, and which accrue to all customers, should weigh heavily in the Commission's deliberations. Whatever may be said about the factors which opponents of the rule choose to highlight, it is clear that even if accepted, their assertions do not refute the basic truth that demand response reduces LMP while enhancing reliability of grid operations. It is respectfully suggested that this is an important consideration under the Federal Power Act.

Some commenters note that the Commission has not found current rates in the organized markets to be 'not just and reasonable' and they therefore conclude that the proposed rule is not justified.[35] The assertion that the Commission has not found existing rates unjust and unreasonable may or may not be accurate, but even if accurate, the Commission is not precluded from undertaking initiatives to improve the markets. If this were not so, the Commission would be stymied in all its attempts at reform. The Federal Power Act is not so stifling as asserted by some parties.

Demand response has enabled RTOs to maintain reliable service under stressed conditions and to do so at less cost than would have obtained absent demand response in the market.[36] Demand response has contributed to the maintenance of just and reasonable rates. The Commission has at its disposal a tool to insure that rates remain at just and reasonable levels—failure to make use of this tool will lead to rates that are higher than they need to be.

There is extensive market mitigation in all of the organized markets.[37] The existence of this extensive mitigation indicates that market power is a problem plaguing the markets even after many years of reform. The extent of the market power issue is demonstrated

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[35] P3 at 17-18.

[36] See Testimony of Andrew Ott, Docket No. AD07-11-000 (April 23, 2007)

[37] EPSA at 39.

by PJMs recent RPM auction, in which all existing suppliers failed the Market Structure Test and all existing resources were mitigated.[38] Enhanced demand response can address this problem of market power to some extent—and mitigate it somewhat via improved market conditions rather than through an administrative remedy.

XI. LMP Compensation Is Required To Bring Demand Response to Market.

There is virtually no demand response participation today in the energy markets.[39] On the other hand, there is significant demand response participation in the capacity markets. Indeed, many of the commenters highlight the significant participation in the capacity markets. Their argument proves too much. The difference in participation levels is attributable in part to the difference in the market rules; demand response is paid the clearing price in the capacity markets today, it is not paid the clearing price in the energy markets. Much like any other service or product provider, demand response reacts to the market conditions it faces. The current level of energy market compensation has produced little demand response.

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[38] PJM 2013/2014 Base Residual Auction Results May 14, 2010

[39] See, for example, ISO-NE Figure 1, page 9. Also, in 2008, PJM system sales totaled 759,000,000 MWh. Demand response provided 452,000 MWh, or .06 per cent of the total.

PJM notes that demand response settlements in the energy market declined after the compensation was reduced, but that site registrations capable of participating in the energy market increased.[40] The proper metric for evaluating the adequacy of compensation is, of course, actual curtailments of usage (settlements), not registered sites. Indeed, PJM's data highlights the potential of demand response to participate if compensation was adequate. It also illustrates the point that LMP-G compensation is inadequate to produce actual curtailments.

XII. A Customer's Bill Savings Are Not Compensation; Nor Are They a Cost to Other Customers.

Several commenters posit that payment of LMP to demand response will produce inefficient results when one considers both the bill savings and the compensation received by the customer.[41] The reference to efficiency in these arguments is a broad-based global reference to choices that consumers might make between hundreds of thousands of competing products, including electricity. It says nothing about the relative efficiency of grid operations when demand response is paid LMP.

A customer's bill savings are not compensation paid by the market. They are external to the market.

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[40] PJM, at 3.

[41] PJM Power Providers at 29-30.

They cost other customer's nothing. The only compensation paid by the market is LMP. And LMP will be paid to the demand response provider only if it displaces a more expensive offer from another source. From the perspective of the RTO (and the customers), the marginal cost of a demand resource will always be less than LMP, otherwise it will not clear. Therefore, payment of LMP to demand response is consistent with efficient operation of the grid. The Commission's subject matter jurisdiction extends to operation of the electric markets. It cannot affect the prices of all the other products traded in the economy.

Consider the example set forth by ISO New England at pages 24-26 of its filing. The example adds the demand response provider's bill savings ($500) and LMP compensation ($1500) and concludes that payment of the demand resource is inefficient because the total exceeds the cost of the marginal unit on the grid, that is, LMP. The example masks two relevant points: First, the cost to the grid (the cost to all other customers) of paying for the demand response is $1500, the LMP payment. The bill savings are not a cost borne by the market. Second, the dispatch of the demand response had the effect of reducing LMP (because it cleared) and this is a benefit to all other customers that is not reflected in the example.

Opponents of the proposed rule characterize the payment of LMP to demand response as a 'subsidy' They assert that some customers ought not to be re-

quired to subsidize other customers.[42] It is difficult to reconcile this argument with the argument made by these same parties that 'excessive demand response compensation' will reduce LMPs too much for the good of the suppliers. Undoubtedly, greater quantities of demand response will reduce prices, but this effect cannot be characterized as a subsidy from other customers because those non-curtailing customers are the beneficiaries of the reduced LMPs.

The proper focus of attention should be on the positive effects that paying LMP to demand response will have in terms of market price reduction, market power mitigation, and grid reliability. All of these effects are positive and further the statutory goals of reliable service at just and reasonable rates.

XIII. A Customer Baseline Method Exists Which Addresses the Concerns That Have Been Expressed.

Some commenters note that the proposed rule creates measurement and verification issues because the rule requires payment of LMP for reductions from expected levels of consumption in all hours—and therefore requires calculation of a customer baseline.[43] The argument is something of a red herring because a customer baseline will have to be calculated regardless of the compensation level.

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[42] EPSA at 60.

[43] See ISO NE, at 31

More importantly, there are means available to address the customer baseline issue if one is actually willing to consider solutions. For example, it is asserted that "No baseline estimation methodology that relies upon historical customer meter data can accurately and reliably estimate what an individual customer's energy usage pattern would have been if that customer responds frequently to price signals."[44] Assuming that the concern is legitimate, there are estimation methodologies available that do not rely upon historical customer meter data.

The econometric approach proposed below addresses the issues and avoids the problems associated with the standard approach to calculating CBL.[45] The proposed method will work particularly well for customers who perform active load management in response to wholesale prices. Customers who actively participate in the demand response programs will implement more efficient operations of their facilities, including a willingness to adjust building temperature settings, temporary activation of interruptible loads, and other techniques in response to high wholesale market prices.

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[44] Id.

[45] Viridity attempted to pursue an alternative CBL approach with ISO NE. However, the suggestion was rejected by the stakeholder process as being inconsistent with existing rules. Viridity will re-engage the ISO (and others) on this issue but suggests that the Commission should also consider docketing a separate proceeding to consider the matter.

A customer's energy consumption resulting from business-as-usual (BAU) operation of its facilities will be used as the Customer Baseline Load. However, instead of relying on historical energy consumption data to calculate the baseline, the calculation of the CBL can be based upon a physical model of a client's energy consuming facilities and its 'business as usual' operating plans. The proposal is predictive, not backward looking.

A solution which is responsive to the problem is to employ a mathematical expression of what consumption would be absent any response to price, instead of using historical loads as indicators of present consumption levels. The CBL can reflect a physical model of the energy consuming facilities and operating plans of the user. The reasonableness of the CBL calculated in this way is dependent upon the algorithms employed and upon the reasonableness of the inputs. The inputs and algorithms can be shared at any time with the interested parties, the LSE, the RTO, and others who have a legitimate interest. The calculation will be transparent.

The calculation of consumption for each day would reflect all of the known relevant variables, such as building materials, thermal properties of the building, building occupancy, ambient and desired temperature, operations for the day, etc. In brief, parameters such as the following will be included: HVAC building controls, pre-identification of interruptible loads and

their pre-defined response to a price signal; desired temperatures, etc.

The proposed method has several advantages. It is objective and it is completely transparent. The inputs and the algorithms can be reviewed. The 'business as usual load' is defined in advance by an engineering model and cannot be gamed by behavior designed to influence the CBL calculation. Moreover, the approach measures CBL on the actual day for which a settlement is proposed; thus, it fairly represents load, unlike a historic average which may not do so.

In sum, frequent curtailments in response to price signals, which are legitimate and verifiably taken in response to price, can and should be a part of the market mechanism. And reasonable means exist to establish the baseline for the measurement, if one is willing to consider solutions.

XIV. The Need to Allocate the Cost of Demand Response Costs Should Not Delay Implementation of The Proposed Rule.

Several parties noted in their comments that if the Commission implements the proposed rule that allocation and settlement issues arise which must be addressed. They suggest that "the Commission will need to propose further rules and seek comment before such rules can be implemented."[46] While alloca-

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[46] See for example, ISO NE, at 37.

tion issues should be addressed they need not, and should not, be used an excuse to delay implementation of the proposed compensation rule. Therefore, if the Commission determines to address allocation issues in a separate proceeding, it should direct immediate implementation of the compensation rule, with the current allocation of demand response costs at each RTO being used until such time as the Commission sets forth a different methodology.

If the Commission believes that it can adopt an allocation methodology now, it should adopt the simple and straight-forward mechanism of dividing the total of all payments to generation and demand resources by actual load. This process insures that payments in the energy markets to generation and demand response will equal collections from consumers. Contrary to the assertions of some commenters, the allocation issue can be resolved without resorting to draconian measures such as imposing specific rate structures on the competitive market (such as the proposal to condition payments to demand response upon an obligation to purchase expected consumption in the day-ahead market).

In considering the allocation issue the Commission should be guided by the well established, basic principle that costs should be allocated to the beneficiaries of a service. A principal benefit of enhanced demand response is its ability to discipline LMP, which benefits all customers. Therefore, a broad based allocation of

the costs of DR is appropriate because the benefits will be broad based.

The Commission should be particularly wary of suggested allocation schemes that have the effect of undoing the compensation rule. For example, some parties suggest that the cost of demand response should be allocated to the 'host' LSE. This proposal is tantamount to allocating the cost of demand response to the customer providing the service—and will completely remove the financial reason for the customer to provide the service. If the Commission permits an allocation that is so narrowly drawn it will effectively undo all the good that would be accomplished by the proposed compensation rule. Moreover, this type of allocation does not allocate the cost to those who benefitted from the LMP reduction.

XV. The Proposed Rule Will Not Create A Plethora of Inefficient Behind the Meter Generators.

Some commenters worry that compensation for demand response at LMP in all hours will unleash a mass migration of generation "behind the meter"—upsetting the entire dispatch order and increasing air pollution from inefficient, high-polluting generators.[47] Such worries are grossly overstated. Wholesale market rules, and environmental regulations, combine

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[47] Exelon at 9.

to limit severely the ability to deploy such generators to support demand response.

A recent federal regulation severely limits the ability of behind-the-meter emergency generators to support demand response.[48] Unless such generators install expensive air pollution control devices, the regulation allows them to operate for no more than 15 hours per year as part of a demand response program. Even in those 15 hours, the generator cannot run unless the RTO "has determined there are emergency conditions that could lead to a potential electrical blackout, such as unusually low frequency, equipment overload, capacity or energy deficiency, or unacceptable voltage level."[49] States in at least three RTOs/ISOs have adopted similar limitations.[50]

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[48] U.S. Environmental Protection Agency, "National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines," 75 Fed. Reg. 9648 (March 3, 2010).

[49] Id.; see 40 CFR 63.6640.

[50] See, e.g., Connecticut Administrative Code, Sec. 22a-174-22(a); New York Codes, Rules, and Regulations, Sec. 227-2.2(b)(7); New Jersey Administrative Code Sec. 7:27-19.1; see also Memorandum of Understanding Among the States of the Ozone Transport Commission Concerning the Incorporation of High Electrical Demand Day Emission Reduction Strategies into Ozone Attainment State Implementation Planning, March 2, 2007.

XVI. The Proposed Rule Should Apply in All Organized Markets.

Several commenters urge the Commission to allow each RTO to craft a rule that reflects its specific, unique characteristics.[51] However, these requests are vague and do not delineate any meaningful differences between the RTOs that would justify a different rule. Indeed, the similarities between the RTOs that are relevant to this issue are significant. Specifically, each RTO employs a form of security constrained economic dispatch and a form of Locational Marginal Pricing. These two attributes are the cornerstones of wholesale market operations. They determine which units are dispatched and at what price. Consistent with these universal market rules, demand response should compete with supply resources on a level playing field. Demand resources should be dispatched if they clear in a security constrained economic dispatch algorithm, and if dispatched, should be paid LMP. Opponents of the proposed rule have offered no differences in RTO characteristics that are more significant than these critical similarities.

XVII. LMP Compensation Should Apply in All Hours.

Those commenters who oppose the proposed rule note that payment of LMP in all hours could impose costs on the general body of ratepayers.[52] There are

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[51] See for example, EPSA at 62.

[52] See for example, P3 at 37.

four points that should be noted with respect to this concern. First, LMP is the correct compensation level in all hours because the prevailing LMP at any given hour represents the value of an increment of supply or decrement of load during that hour. Second, the concern reflects an unlikely circumstance. That is, the only way that demand response could impose net costs on some customers would be in the unlikely event that that there is a great deal of demand response (suggesting a large cost) coupled with a minimal effect on LMP (suggesting a cost curve with little or no slope). Third, so long as demand response clears in a competitive auction it always displaces a more expensive unit and therefore reduces the 'revenue requirement' associated with satisfying load. Fourth, if a concern remains, an easily implemented solution (proposed by the Consumer Demand Response Initiative) exists which can insure that demand response is compensated only in situations in which it makes all customers better off.

A dynamic threshold can be adopted in which the dispatch queue is always run both with and without demand response being dispatched. The cost of compensating demand response, and its effect on LMP (the benefit), will both be captured in the run in which demand response is dispatched. So long as this run produces a lower cost to consumers than the run absent demand response, consumers are better off and demand response should be dispatched and compensated.

Some parties have proposed a static threshold for measurement of the point at which demand response may cost some ratepayers more than it saves them. This approach represents an estimate of the 'cross-over' point and thus will be wrong on occasion, as most estimates are. The dynamic threshold noted above can be precisely calculated over and over again and thus will produce a more accurate measure.

Conclusion

The Commission should make the proposed rule final without delay and should, to the extent it deems it necessary, adopt allocation and cost recovery processes needed to implement the rule.

Respectfully submitted,

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FEDERAL ENERGY REGULATORY COMMISSION,
PETITIONER

v.

ELECTRIC POWER SUPPLY ASSOCIATION, ET AL.

ENERNOC, INC., ET AL., PETITIONERS

v.

ELECTRIC POWER SUPPLY ASSOCIATION, ET AL.

ON WRITS OF CERTIORARI
TO THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

JOINT APPENDIX
(VOLUME 2)

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TABLE OF CONTENTS

Page

VOLUME 1

Court of appeals docket entries 1
R.2, Notice of Proposed Rulemaking (Mar. 18, 2010) 19
R.10, Comments of the Illinois Commerce Commission (May 6, 2010) 60
R.18, Comments of the Electric Power Supply Association (May 12, 2010) 80
Attachment 1, Implications for Consumers of the NOPR's Proposal to Pay the LMP for All Demand Response (May 12, 2010) 181
R.44, Notice of Intervention and Comments of the New York State Public Service Commission (May 13, 2010) 220
R.50, Comments of the Public Utilities Commission of Ohio (May 13, 2010) 236
R.55, Comments of Verso Paper Corp. in Support of the Notice of Proposed Rulemaking (May 13, 2010) 244
R.58, Comment of the Federal Trade Commission (May 13, 2010) 281
R.74, Comments of the Organization of MISO States (May 13, 2010) 302
R.76, Comments on Notice of Proposed Rulemaking of PJM Interconnection, L.L.C. (May 13, 2010) 314
R.79, Comments of the Delaware Public Service Commission (May 13, 2010) 348
R.82, Comments of Viridity Energy, Inc. 350
R.83, Comments of American Public Power Association and the National Rural Electric Cooperative Association (May 13, 2010) 382

Table of Contents—Continued: Page

R.86, Comments of the New York Independent System Operator, Inc. (May 13, 2010) 404
R.91, Notice of Intervention, Comments, and Request for Clarification of the Public Utilities Commission of the State of California (May 13, 2010) 425
R.93, Comments of Steel Producers (May 13, 2010) 439
R.94, Comments of EnerNOC in Response to Notice of Proposed Rulemaking (May 13, 2010) 452
R.100, Comments of ISO New England Inc. (May 13, 2010) 467
R.105, Comments of the Midwest Independent Transmission System Operator, Inc. (May 13, 2010) 535
R.113, Comments of Wal-Mart Stores, Inc. to the Notice of Proposed Rulemaking on Demand Response Compensation in Organized Wholesale Energy Markets (May 13, 2010) 558
R.123, Comments of Potomac Economics, Ltd. (May 13, 2010) 575
R.124, Comments of the Independent Market Monitor for PJM (May 13, 2010) 587
R.128, Joint Comments of Public Interest Organizations on Notice of Proposed Rulemaking (May 14, 2010) 599
R.131, Comments of Old Dominion Electric Cooperative on Notice of Proposed Rulemaking (May 14, 2010) 616
R.137, Reply Comments of Viridity Energy, Inc. 658

VOLUME 2

R.142, Reply Comments of the Electric Power Supply Association (June 30, 2010) 704
R.149, Reply Comments of the Demand Response Supporters (Aug. 30, 2010) 791

Table of Contents—Continued: Page

Attachment A, Reply Affidavit of Dr. Alfred E. Kahn 829
R.153, Transcript of Demand Response Compensation in Organized Wholesale Energy Markets Technical Conference (Sept. 13, 2010) (excerpts) 852
R.160, Speaker Materials of Megan Wisersky, Electric Planning Manager, Madison Gas & Electric Co on Behalf of Midwest Transmission Distribution Utilities, Presented at the Technical Conference, Demand Response Compensation/Organized Wholesale Energy Markets (Sept. 13, 2010) 926
R.187, Post-Technical Conference Comments of the American Public Power Association (Oct. 13, 2010) 941
R.201, Post Conference Comments of the Electric Power Supply Association (Oct. 13, 2010) 958
R.209, Comments of the Midwest Independent Transmission System Operator, Inc. (Oct. 13, 2010) 978
R.232, Joint Request for Rehearing of the Electric Power Supply Association, et al. (Apr. 14, 2011) 998
R.233, Request for Rehearing of the Organization of MISO States (Apr. 14, 2011) 1024
R.235, Request for Rehearing and Clarification of Old Dominion Electric Cooperative, American Public Power Association and the National Rural Electric Cooperative Association (Apr. 14, 2011) 1036
R.239, Request for Rehearing of the Edison Electric Institute (Apr. 14, 2011) 1075
R.240, Request for Rehearing of the Competitive Power Supply Associations (Apr. 14, 2011) 1118

Table of Contents—Continued: Page

Documents filed in FERC Docket No. EL09-68-000:
Supplemental Report and Submittal of PJM Interconnection, L.L.C. in Support of Further Commission Action on Rehearing (Aug. 26, 2009) 1235
Comments and Protest of Demand Response Supporters (Sep. 16, 2009) 1278
Attachment A, Affidavit of Alfred E. Kahn 1336
Attachment D, Affidavit of Ron Belbot On Behalf of Demand Response Supporters 1348

UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. RM10-17-000

DEMAND RESPONSE COMPENSATION IN ORGANIZED WHOLESALE MARKETS

June 30, 2010

REPLY COMMENTS OF THE ELECTRIC POWER SUPPLY ASSOCIATION

Pursuant to Rule 213 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or the "Commission"),[1] the Electric Power Supply Association ("EPSA")[2] hereby submits reply comments on the notice of proposed rulemaking issued in the above-captioned proceeding on March 18,

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[1] 18 C.F.R. § 385.213 (2009).

[2] EPSA is the national trade association representing competitive power suppliers, including generators and marketers. These suppliers, who account for 40 percent of the installed generating capacity in the United States, provide reliable and competitively priced electricity from environmentally responsible facilities. EPSA seeks to bring the benefits of competition to all power customers. The comments contained in this filing represent the position of EPSA as an organization, but not necessarily the views of any particular member with respect to any issue.

2010.[3] In the NOPR, the Commission proposes to revise its regulations to require independent system operators ("ISOs") and regional transmission organizations ("RTOs") with tariff provisions permitting demand response ("DR") providers to participate in energy markets to pay these DR resources, in all hours, the market price for energy (*i.e.*, the full Locational Marginal Price ("LMP" or "full LMP")). As detailed in EPSA's initial comments in this proceeding,[4] EPSA and its members fully support the participation by diverse resources in ISO/RTO markets and EPSA's members have been involved in numerous proceedings and efforts to develop viable, properly structured DR products. Additionally, EPSA member companies are involved in the provision of demand response products in several markets across the country. Despite

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[3] *Demand Response Compensation in Organized Wholesale Energy Markets*, Notice of Proposed Rulemaking, 130 FERC ¶ 61,213 (2010) (the "NOPR"). The NOPR did not specifically set a date for the submission of reply comments. Nonetheless, these reply comments are a permissible answer under Rule 213(a)(3) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(3) (2009), inasmuch as the comments to which EPSA is responding are not pleadings to which answers are prohibited under Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2009). To the extent necessary, EPSA moves pursuant to Rule 212 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.212 (2009), for leave to file these reply comments.

[4] *See* Comments Of The Electric Power Supply Association at 2-3, Docket No. RM10-17-000 (filed May 12, 2010) (the "EPSA Initial Comments").

this full support of the role of DR in functional energy markets, EPSA and numerous other independent sources and stakeholders either strongly oppose or raise serious concerns regarding subsidizing DR through payment of full LMP in all hours in all cases. Unfortunately, the NOPR's proposal will not achieve its stated goal of ensuring that ISO/RTO prices are just and reasonable due to the significant legal, economic, policy, and operational flaws identified by EPSA and numerous other diverse commenters in these proceedings.

I. BACKGROUND AND SUMMARY

The Commission's NOPR proposing a generic compensation approach for DR acting as a resource in organized wholesale energy markets has wrought comments from approximately 130 entities representing a spectrum of interested stakeholders and market participants. An extensive and impressive array of those comments supports the participation of DR in the wholesale energy markets but does not support the compensation as proposed in the NOPR as the best avenue to incent beneficial levels of price responsive demand. Unfortunately, some commenters who fully support the NOPR have attempted to mischaracterize the discussion as simply a clear delineation between those who are "for" DR and those who are "against" DR (erroneously implied to be primarily suppliers). Somehow, to oppose full LMP compensation in all hours on all days is merely a lack of "vision" by those attempting to keep the national electricity grid anti-

quated and staid.[5] Instead, the record in this proceeding is heartening as it indicates that a chorus of diverse commenters, many representing states and markets, share the fundamental concerns raised by competitive suppliers in initial comments. As EPSA has stressed repeatedly, DR is an important and valuable element of the electricity markets. How DR is compensated, however, does not represent a theological battle or a "dialectic interrogation"[6] as if the Commission were a plenary legislative body. Rather the Commission is no doubt well aware that it is bound by statutory responsibilities, the limitations of the law and the realities of the electric grid. In that vein, numerous comments from diverse parties were pragmatic, constructive discussions of the proposal, raising serious questions that merit consideration (including alternatives that may reflect regional and state facts and situations). These are considerations and elements that should be addressed in any final rule as they were not addressed in the brief NOPR and its very limited proposed tariff language.

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[5] *See* Reply Comments of Viridity Energy, Inc., Docket No. RM10-17-000 (filed June 18, 2010) ("Viridity Reply Comments"), pp. 5-6.

[6] *See Affidavit of John C. Tysseling, Ph.D., regarding Reply Comments of Viridity Energy, Inc.*, Docket No. RM10-17-000 (June 18, 2010), p. 5. "With its wholesale market leadership, the Commission must also foster and facilitate a dialectic interrogation of its policy impacts on retail market regulation, load serving entities ("LSEs") and retail customers."

While parties differ on preferred compensation formulas, there is now extensive commentary in the record that there must be some purchase requirement or representative offset to allow a DR provider to "sell" a commodity that it owns to the ISO/RTO. Without this purchase or a reflection of a purchase, there is no question that one megawatt of supply is not equal to one megawatt of demand. If demand is to be treated as a comparable resource to supply, concerns raised in the record should be addressed in any final rule. Additionally, numerous commenters noted that even if full LMP is designated as the appropriate compensation, that compensation should not apply in all hours on all days; rather, there should be some threshold, triggers or defined circumstances in which DR creates value for the system during peak or scarcity periods, without which most consumers will be harmed. While the NOPR offers the proposition that one megawatt of demand is equal to one megawatt of supply, that concept is belied by feedback from many diverse interested parties and market participants.

Certainly demand response is an integral part of a properly structured competitive electricity market. However, the contention in the NOPR that some undefined level of additional demand response is *always needed* in order to make the organized markets competitive, or mitigate market power among suppliers, is not supported by an array of commenters; instead, concerns are raised that the full LMP compensation proposal would distort those markets. Several regu-

lators and consumer interests raise concerns that the NOPR compensation proposal results in subsidies for demand response which will increase rates for residential consumers that are unable to bid their load in to the wholesale market, and in fact creates barriers to a plethora of dynamic retail response programs being pursued at the local and state levels.

Additionally, a true barrier to economic DR lies at the retail level, where infrastructure to support DR is only in early stages of development. Recently the head of a well-known DR provider, EnerNOC CEO Tim Healy, noted "Demand response is probably trying to graduate from first innings of the game to maybe the top of the second inning now, where we're seeing demand response thought of as not just some sort of emergency resource but as an integrated resource."[7] Exemplifying that we are in early innings, the Gridwise Alliance, a consortium of public and private partners, is organizing the Gridwise Global Forum to be held in Washington, D.C., in September 2010 in order to respond to a smart grid "backlash" in the states. According to coverage in Energy Washington, "Public acceptance of the smart grid and how customers view their energy use are topics that have never been thoroughly examined in a way that can provide insight on how best to shape policies, say sources with the

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[7] See "DR's fate debated by power industry dignitaries," covering the National Town Meeting on Demand Response & Smart Grid in Washington, DC, *Restructuring Today*, Thursday, June 24, 2010, p. 1.

group."[8] Similarly, the American Council for an Energy-Efficient Economy ("ACEEE") has just released a report looking at whether smart meters are sufficient to empower residents to cut their household electricity use significantly:

> ACEEE found that three of the most promising approaches in the short- to medium-term include enhanced billing, daily/weekly feedback, and "off line" and Web-based real-time feedback. However, far-reaching programs that go beyond "smart meters" are few and far between. According to ACEEE, no U.S. utilities are currently providing the full range of needed services John A. "Skip" Laitner, director, Economic and Social Analysis, American Council for an Energy-Efficient Economy, said: "The bottom line here is very simple: Smart meters in and of themselves are just not 'smart' enough to get the job done for consumers and our economy."[9]

There remain questions as to where the country and states are on the spectrum in the use and reliance of DR as a supply resource equivalent in the wholesale

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[8] *"Major Smart Grid Forum Will Tackle Policy Issues, Consumer 'Backlash,'" Energy Washington, June 28, 2010.*

[9] "ACEEE Study Finds "Smart Meters" Not Smart Enough To Slash Residential Power Use and Significantly Reduce Consumer Electric Bills," ACEEE press release, June 29, 2010, available here: http://www.aceee.org/press/e105pr.htm.

markets, and whether the NOPR compensation proposal would move us into the next inning.

In a similar vein, NERC addresses the growing role of DR in electricity markets, noting that it can provide reliability benefits during off-peak periods as well as during peak periods, but NERC also notes,

> Unlike traditional generating resources with many decades of historic data for analysis, the longterm projections of Demand Response resources involve greater forecasting uncertainty. For example, the New England and New York electricity markets integrate large Demand Response programs; however, the long-term availability of these resources remains uncertain. While extremely valuable in planning and operations, less understood attributes of the resources, such as response fatigue or economic-base participation rates must be carefully monitored to assure they do not pose reliability issues in the future. In most cases, forecasting of Demand Response is not performed. Rather, projections are based on resource requirements and the amount contracted during a commitment period.[10]

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[10] *NERC 2009 Long-Term Reliability Assessment 2009-2018*, p. 19. Available here: http://www.nerc.com/files/2009_LTRA.pdf. The Report also notes that going forward, "To monitor historical performance of Demand Response, NERC, in coordination with the North American Energy Standards Board (NAESB), is developing the Demand response Availability Data System (DADS) to assess the capability and availability of Demand Response." p. 20.

This relatively nascent state of DR as a resource motivated Congress to direct the Commission to develop the recently published National Action Plan on Demand Response to be implemented over the next five to ten years.[11] That report focused on how local and regional programs and products can best be developed, fostered and communicated. At this stage, the NOPR may implement a sweeping wholesale market subsidy that could create unintended negative consequences for the broader development of diverse DR products through the states as Congress intended in section 529 of the Energy Independence and Security Act of 2007 requiring the action plan.

If, as the NOPR proposes, demand is to be treated either equally or comparably in order to be compensated equally or comparably to supply, it must follow that demand response providers should and must be subject to the same or comparable market rules, mitigation mechanisms, penalties and requirements as suppliers. If, however, DR provides a necessary and important balancing service (as many of the supporters of the NOPR proposal agree it does), then both treatment by the market operator and compensation should reflect that more limited role. Further, several comments express the importance of dealing with the very difficult issues of cost allocation and measurement and verifiability of demand response in tan-

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[11] *National Action Plan on Demand Response*, Docket No. AD09-10-000 (June 17, 2010); available here: http://www.ferc.gov/legal/staff-reports/06-17-10-demand-response.pdf.

dem with or *in advance* of the consideration and implementation of a uniform compensation mechanism. EPSA agrees.

Finally, there remain fundamental and foundational jurisdictional issues that have not been laid to rest by any of the comments entered in to the record in this proceeding. Simply, the Commission lacks the authority to require "just and reasonable" compensation for the provision of non-jurisdictional demand response services as those services do not represent a FERC-jurisdictional sale for resale. This lack of jurisdiction extends to whether DR compensation "affects" jurisdictional rates. Where the Commission is foreclosed from directly regulating non-jurisdictional rates, it may not circumvent the limits on its statutory authority by claiming to do so based on the fact that such non-jurisdictional rates may "affect" jurisdictional rates. To argue so would read out of the Federal Power Act ("FPA") the express restrictions on the Commission's ratemaking authority in a given state. For reasons stated in EPSA's initial comments, amplified here, and not refuted in other comments to date, the Commission does not have a record in this docket to base jurisdiction on the alternative theory that the NOPR is needed to further mitigate wholesale energy prices.

EPSA's initial comments raised serious concerns over mandating a uniform method of compensation across all RTOs, an approach that the Commission has recently chosen not to utilize in the development of

transmission cost allocation mechanisms, just as it has not with most other RTO design elements.[12] Regional deference and consensus development over a fundamental market element for transmission, and current barriers to the development of additional transmission infrastructure, represents the best approach to achieving answers for particular regional situations, and is the approach that should be employed in this instance as well.

These reply comments focus on four priority issues that deserve emphasis due to the extensive concerns raised by a diverse set of stakeholders in their initial comments, and to underscore that one uniform compensation mechanism which indiscriminately subsidizes one class of market participant is inappropriate and should be reassessed by the Commission. Those four issues are:

A. The DR compensation proposal is not necessary to ensure the competitiveness and efficiency of the ISO/RTO markets.

B. While one megawatt of demand is not equal to one megawatt of supply, for purposes of allowing DR to bid in to energy markets as a resource as proposed, all market rules, mitiga-

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[12] *See FERC Notice of Proposed Rulemaking: Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 131 FERC ¶ 61,253, Docket No. RM10-23-000 (June 17, 2010).

tion, obligations and requirements must apply to DR as well as to supply.

C. A rule establishing a standard compensation for DR must also address measurability and verification requirements, and should reflect suggested changes including an offset and thresholds for participation.

D. The Commission lacks jurisdiction to set just and reasonable rates for DR.

This proceeding could represent a milestone in a process that stretches back to enactment of the Energy Policy Act of 1992 ("EPAct 1992"), the statute that laid the groundwork for the development of competitive wholesale electricity markets and consumers' access to the most cost effective and efficient electric power supply. A continuum of legislative and regulatory actions, including Order No. 888, Order No. 2000, Order No. 890, Order No. 719, EPAct 1992 and the Energy Policy Act of 2005 ("EPAct 2005"), have sought to refine and enhance the viability of those markets and access to supply, using a variety of tools. For this reason, EPSA highlights concerns and questions raised by numerous commenters so that this NOPR not impede the progress which has been achieved to date, and instead may move forward in a responsible, practical, efficient and beneficial manner for consumers and suppliers.

II. REPLY COMMENTS

A. THE DR COMPENSATION PROPOSAL IS NOT NECESSARY TO ENSURE COMPETITIVENESS AND EFFICIENCY OF THE ISO/RTO MARKETS

As EPSA previously noted in this proceeding, there is no showing or evidence in the NOPR that additional steps, such as paying DR resources full LMP in all hours in all cases, is necessary to ensure either the competitiveness of the markets or that wholesale rates continue to be just and reasonable.[13] After reviewing comments filed by interested parties in this proceeding, EPSA further asserts that no other party has submitted evidence to support a finding that this is necessary.

While numerous comments point to one set of facts (PJM savings from DR during the August 2006 record heat wave, discussed below) to support the proposal to pay full LMP in all hours, this evidence of cost savings attributable to DR is offered without context or discussion. In August 2006, PJM experienced a period of extreme stress to its system, resulting in very steep supply curves representing peak demand and high prices.[14] Demand resources at that time were able to

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[13] EPSA Initial Comments, p. 6.

[14] *See* PJM News Release "Early August Demand Response Produces $650 Million Savings In PJM," (issued August 17, 2006). The news release is available here: http://www.pjm.com/~/media/about-jm/newsroom/2006-releases/20060817-demand-response-savings.ashx.

respond, saving a great deal of money for consumers in PJM. It is incontrovertible that DR can have a valuable dampening effect on clearing prices during certain times, and few dispute that payments during those times when benefits accrue to customers should reflect that value. Of note, however, is that this particular example occurred during a time of extreme stress—therefore the savings opportunities were great. The same would not occur during the much more common normal or low stress hours, though the NOPR would pay DR as if it would. In an analysis of different demand response compensation schemes undertaken pursuant to a request from the Maryland Public Service Commission, PJM found that in the highest priced 100 hours the benefits of demand response paid full LMP to consumers remaining on the system are positive. However, the analysis noted,

> [B]ut when considering all hours in the year, these estimates are largely negative figures signifying that for remaining load, the extra payments necessary to support the "Full LMP" while leaving the LSE revenue neutral is far larger that [sic] the reduced expenditures from reduced LMPs resulting from demand response resulting in higher costs to the remaining load versus no demand response at all.[15]

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[15] *See* PJM Interconnection, L.L.C., *Analysis of Load Payments and Expenditures under Different Demand Response Compensation Schemes*, May 12, 2010, available at: http://www.pjm.com/

While DR has value during peak periods and should be compensated appropriately, overcompensation in most conditions is a net negative for customers remaining on the grid, and commenters have not submitted evidence or support detailing the non-economic benefits of overcompensating DR outside of a theoretical polemic stance that this is necessary for the future of electricity.

Additionally, the demand which responded during the 2006 heat wave was a combination of economic DR, capacity DR and emergency program DR, all of which exist today and would very likely respond in a similar manner without the NOPR's uniform pricing mechanism. Certainly EPSA is not aware of anything in the record to date that purports to show the NOPR is necessary and appropriate to replicate the 2006 scenario under those conditions. In fact, the payment of full LMP to economic demand at all times incents such response even when it is not helpful, efficient or economic.

Based on the lack of a showing or evidence that the ISO/RTO markets are not sufficiently competitive or rates are not just and reasonable without the NOPR's DR pricing mechanism, EPSA continues its firm posi-

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markets-andoperations/demandresponse/~/media/markets-ops/dsr/analysis-of-load-payments-andexpenditures.ashx. Note that the full PJM analysis report has been submitted in this record as Attachment B of *Reply Comments of the PJM Power Providers Group and Motion to Accept Reply Comments*, filed June 14, 2010.

tion that the NOPR's DR compensation proposal is simply ***not*** needed to maintain or improve competition in ISOs/RTOs. Nor is this proposed compensation necessary to facilitate participation of economic and efficient DR resources. EPSA agrees with the comments of Battelle Pacific Northwest, et al. who stated that "[s]ubsidies can increase demand-side activity, but do not necessarily bring about the kind of participation that is desired for a mature and competitive market."[16]

The NOPR and certain commenters assert, among other things, that DR resources in wholesale energy markets help to improve the functioning and competitiveness of such markets in several ways, including through lower clearing prices and mitigating generator market power.[17] Contrary to such assertions,

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[16] Response to Federal Energy Regulatory Commission Notice of Proposed Rulemaking, p. 2, David P. Chassin, Battelle Pacific Northwest Division; Lynne Kiesling, Northwestern University; and Michael Giberson, Texas Tech University, Docket No. RM10-17-000, (filed May 13, 2010).

[17] NOPR at P 2-7. Also, see *generally* Comments of the Coalition of Midwest Transmission Customers; Comverge, Inc.; EnergyConnect, Inc. EnerNOC, Inc.; PJM Industrial Customer Coalition; Viridity Energy, Inc. and Wal-Mart Stores, Inc. (collectively, "DR Supporters"), RM10-17-000, (filed May 13, 2010) ("DR Supporters Comments") and Comments of the Consumer Demand Response Initiative, RM10-17-000 (filed May 13, 2010) ("CDRI Comments").

Of note, CDRI is a "an informal coalition of businesses, trade associations, non-profit organizations, and education and health care institutions that seek to provide a voice for electricity consumers of

recent State of the Market (SOM) reports for several RTOs or other RTO market announcements issued since initial comments were submitted in this docket in May 2010 provide additional evidence that organized wholesale markets remain competitive and are sufficiently mitigated without the NOPR's approach. In the event increasing DR resources is intended to provide additional mitigation and further lower wholesale prices already down 50 percent in many organized markets, EPSA asserts there must be a detailed assessment and reconsideration of the applicability of the current mitigation structures and the additional rules and requirements applicable to DR resources to ensure comparability among treatment of resources and to guard against the potential for demand-side market power or the over-mitigation of supply.

Finally, the DR Supporters' arguments that insufficient DR has resulted in diminished grid and market efficiency to the detriment of consumers is unsupported.[18] While EPSA recognizes the benefits that may result from market participation by economic and efficient DR resources, EPSA believes a greater concern to grid efficiency and reliability is the potential for DR "saturation" with increasing (and unspecified but Commission-desired) levels of DR—not subject to

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all sizes in regional and national policy discussions on the future of Demand Response and electricity markets." Membership of CDRI is not available from their representative or online for the purposes of this proceeding.

[18] DR Supporters Comments, pp. 9, 14-15.

the same rules and requirements as supply resources —spurred by an unnecessary subsidy payment. To facilitate grid efficiency and reliability, EPSA submits the Commission should instead take expeditious action to address barriers to development of DR resources, such as the lack of robust scarcity pricing, and encourage the transition to price responsive demand resources.

1. Market Monitors Continue To Determine That ISO/RTO Markets Are Already Competitive And Sufficiently Mitigated

The market monitors for the Midwest ISO,[19] California ISO ("CAISO"), New York ISO ("NYISO"), and ISO New England ("ISO-NE") have all recently issued either annual or quarterly SOM reports for their respective markets, in which they determine these wholesale markets are competitive and sufficiently mitigated today.[20] Collectively, these recent reports solidly underpin the position of EPSA and

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[19] Independent Market Monitor (IMM) Quarterly Report for the Midwest ISO, First Quarter 2010, (issued April 14, 2010). The quarterly report is available here: http://www.potomaceconomics.com/uploads/midwest_presentations/IMM_Report_Q1_2010_Final.pdf. (See pg 2: "Overall, the markets performed competitively while producing slightly higher prices than those in the first quarter of 2009 . . . The energy price increases were primarily due to higher fuel prices. Higher load associated with the economic recovery also contributed to the increase.").

[20] These reports were issued soon after the PJM Independent Market Monitor's SOM report making similar findings for the PJM wholesale markets as referenced in the earlier EPSA Initial Comments in this proceeding.

contradict assertions in the NOPR and by other commenters that increased levels of DR obtained through a subsidy and without clear rules or requirements will somehow provide a needed "check" on highly monitored wholesale electric markets that are and have historically been deemed competitive and thoroughly mitigated. For example, the CAISO's Department of Market Monitoring' ("DMM") annual market report finds that,

> The overall performance of the new day-ahead and real-time markets in 2009 were highly efficient and competitive. Prices in the energy markets were approximately equal to competitive baseline prices that DMM estimates would result under highly competitive conditions.[21]

Furthermore, these reports detail the extent to which DR resources currently participate in aggregate across the various RTO markets, including the capacity, ancillary services and energy markets, representing increased total levels of participation and compensation. For example, the ISO-New England Internal Market Monitor's ("IMM") annual report[22] reflects that the number of megawatts ("MW") of enrolled DR

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[21] CAISO Department of Market Monitoring (DMM), *2009 Annual Report on Market Issues and Performance*, p. 1, (issued April 2010). The DMM Report is available here: http://www.caiso.com/2777/27778a322d0f0.pdf.

[22] ISO New England Internal Market Monitor, *2009 Annual Markets Report* (May 18, 2010). The IMM Report is available here: http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/2009/index.html.

resources rose about 17 percent in 2009, from 2,546 MW in December 2008 to 2,998 MW in December 2009 (IMM Report at 11.) Additionally, the ISO-NE IMM report shows that,

> [P]ayments for all demand-resource programs totaled $111.5 million in 2009. Forward Capacity Market transition payments made to eligible demand resources rose from $77.6 million in 2008 to $106.8 million in 2009 due to increased program enrollments and a higher transition payment rate. (IMM Report at 12.)

Likewise the NYISO's Market Monitoring Unit SOM report details the participation of DR resources in the NYISO markets, "particularly the capacity market where demand resources provide more than 2 GW of supply."[23] The NYISO SOM report also indicates that the most significant barrier to widespread participation by retail loads is that most of them are not exposed to wholesale prices and discusses efforts

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[23] Potomac Economics, Market Monitoring Unit, *2009 State of the Market Report, New York ISO Electricity Markets*, p. 12, (issued April 2010). The NYISO 2009 SOM report is available here: http://www.potomaceconomics.com/uploads/nyiso_presentations/2009_NYISO_SOM_Final_4-30-2010.pdf. *Also see* Quarterly Report on the New York ISO Electricity Markets, First Quarter 2010, Potomac Economics, Market Monitoring Unit, (issued May 2010). The NYISO Quarterly Report is available here: http://www.potomaceconomics.com/uploads/nyiso_presentations/NYISO_Quarterly_Report_2010-Q1_final.pdf.

by the ISO to develop ways to allow price-responsive retail loads to participate in the wholesale market.[24]

Also of note, PJM recently announced the results of its Reliability Pricing Model (RPM) capacity auction for the June 2013 to May 2014 delivery year. The results show that renewable resources, demand response and energy efficiency made up nearly three-fourths of the new capacity available and about 7 percent of the resources clearing the auction.[25] Specifically, the RPM auction procured 152,743 MW of capacity resources including 9,282 MW of cleared demand response, which represents a 32 percent increase from last year's RPM auction for the 2012-2013 delivery year.[26]

In sum, the underpinning propositions in the NOPR that the ISOs/RTOs are not competitive or sufficiently competitive, or that DR is not participating in the markets in a beneficial or robust manner, are incorrect. In part, the debate over market competitiveness and the impacts of DR participation stems from a lack of clarity or discussion about what levels of DR would be deemed sufficient by the Commission, why all

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[24] Id. *Also*, the PJM Independent Market Monitor has made similar findings. *See* EPSA Initial Comments in this proceeding at pp. 7, 24-26.

[25] *See* PJM News Release, "*Renewable Resources Grow in PJM's RPM Auction*," issued May 14, 2010. The PJM news release is available here: http://www.pjm.com/~/media/about-pjm/newsroom/2010-releases/20100514-rpm-auction-results-2013-2014.ashx.

[26] Id.

types of DR are not viewed and assessed as a whole in terms of their important role in the ISOs/RTOs, and what measurement of competitiveness is driving the NOPR proposal that is not recognized or supported by independent market monitors.

2. DR Resources Must Be Subject To Market Rules and Mitigation If They Bid In to Energy Markets as a Resource

If, as it appears, a critical contention of the NOPR is that the DR compensation proposal is an important means of further mitigating market power in wholesale markets, then EPSA submits that current ISO/RTO market mitigation measures should be re-assessed, otherwise the wholesale markets will be over-mitigated, given the findings above from the various ISO/RTO market monitors regarding the wholesale markets' competitiveness and sufficient mitigation that is already in place. However, if DR is going to bid in to energy markets as a resource that is to be comparable with supply resources, then it must also be subject to the full array of rules, requirements and penalties applicable to supply resources, including market mitigation and reliability measures and registration across the ISO/RTO markets and NERC reliability regions.

However, based on the record established by comments in this proceeding, it is clear that demand response products have different physical abilities from generation products, and in fact, that all demand response products are not equal to each other in terms of dispatchability, capabilities and services offered. As the Commission's regulations set out to treat demand

response products comparably, it is important to consider also a demand responder's obligations as a market participant. If the resource cannot perform under these market obligations, yet is paid what the NOPR suggests, the resource will be getting preferential treatment, not comparable or even equitable treatment, though EPSA and others contend that LMP without any purchase or equivalent offset is in fact an unjustified subsidy for that product. However, in order to move towards true comparability, a resource's ability to conform to and perform pursuant to the same market rules and standards must be part of the analytical equation, though this was not addressed in the NOPR proposal in any manner whatsoever.

Old Dominion Electric Cooperative ("ODEC") notes that in PJM,

> The rules under which demand response being treated as a resource operate create disparities between generation resources and demand resources. Unlike generation resources that are dispatched by system operators, demand response is a voluntary reduction in electric consumption in response to price and to the end-use facility operational needs, such as an industrial customer needing to immediately complete a production run to fulfill a customer order. The amount of load reduction is determined by the responder and can vary from hour to hour in PJM's program. There is no potential cost penalty for demand resources if they choose not to curtail, and a responder's curtailment decision is

> generally made without consideration of the grid's operation and stability.[27]

ODEC further notes that critical market mitigation rules do not apply to demand resources. "Thus, in order to be considered comparable to generation resources, demand resources participating in the wholesale energy markets would have to be dispatchable and subject to requirements that are comparable to generation resources. This is not the case at this time."[28]

Market obligations for supply bidding into the energy markets ensure reliability of the system and protect consumers from unlawful exercises of market power. While supporters of the Commission's proposal spent many pages extolling the virtue of demand response as a balancing service, there was not commensurate emphasis or discussion of DR's ability to adhere to market rules and standards in order to support the proposition of either equivalent or comparable compensation.

While industrials and DR providers who seek the proposed subsidy state that, "sufficient compensation will call forth substantial amounts of demand response

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[27] Request For Leave To Submit One Day Out-Of-Time And Comments Of Old Dominion Electric Cooperative On Notice Of Proposed Rulemaking, p. 10, Docket No. RM10-17-000, (filed May 14, 2010) ("ODEC Comments").

[28] Id., p. 12.

and that inadequate compensation will not,"[29] this stance is not supported by the operation of the system. Valuation for demand response products, the services they can provide and the market obligations they can fulfill should be decided on a market-by-market, product-by-product basis. Over-compensating DR as a general category simply to incent more, with no regard to how its value compares with the benefits it brings to the system, is not the answer. Indeed, even vehement supporters of the NOPR's proposal have said that "even multiples of full LMP compensation will be insufficient to attract greater levels of demand response"[30] unless the Commission works to remove barriers to market entry for those resources. That should be an important focus of market participants, consumers, states, the regional wholesale markets and the Commission.

Additionally, the Commission must carefully assess the role of DR resources in applying mitigation measures, such as the three-pivotal supplier test utilized in PJM. This is not a frivolous matter. The incentive for uneconomic and inefficient market participation by DR resources, as well as the potential for the exercise of demand-side market power under the full LMP compensation proposal has been raised by a significant

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[29] Comments of Viridity Energy, Inc., p. 5, Docket No. RM10-17-000, (filed May 13, 2010) ("Viridity Initial Comments").

[30] DR Supporters Comments, p. 31.

number of parties in this proceeding.[31] Among the aspects of FERC's increased oversight that must be

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[31] For example, the following economic experts raise concerns regarding the incentive for uneconomic and inefficient market participation by DR resources under the NOPR proposal: Affidavit of Dr. Roy J. Shanker, p. 2, Exhibit 1 to Comments of the New England Power Generators, Docket No. RM10-17-000 (filed May 13, 2010) (Shanker Affidavit); Comments by Constantine P. Gonatas of CPG Advisors, Inc., p. 11, Docket No. RM10-17-000 (filed April 13, 2010); Comments of Dr. Samuel Newell, Dr. Kathleen Spees, and Philip Q. Hanser, pp. 2-3, Docket No. RM10-17-000, (filed May 13, 2010) (The Brattle Group); Comments of Dr. Charles J. Cicchetti, Ph.D., Docket No. RM10-17-000, (filed April 27, 2010); Comments of Robert L. Borlick, Energy Consultant, p. 4, Docket No. RM10-17-000, (filed May 13, 2010) (Borlick Comments); William W. Hogan, "Implications for Consumers of the NOPR's Proposal to Pay the LMP for All Demand Response, p. 2, Attachment 1 to the EPSA Initial Comments, Docket No. RM10-17-000, (filed May 12, 2010) (Hogan Paper). Also, see Footnote 82 reflecting the numerous commenters, who raise concerns that developing accurate baselines is essential to guard against the potential for abuse.

Additionally, the following comments all raised concerns over uneconomic and inefficient market behavior by DR resources in response to the NOPR proposal: *Comment of Battelle/Pacific Northwest Laboratories*, Docket No. RM10-17-000 (May 13, 2010); *Comments of Capital Power Corporation*, Docket No. RM10-17-000 (May 13, 2010); *Comment of Consolidated Edison Energy, Inc., et. al*, Docket No. RM10-17-000 (May 13, 2010), p. 2; *Comments of Edison Electric Institute*, Docket No. RM10-17-000 (May 13, 2010), p. 22; *Comments of Exelon Corporation*, Docket No. RM10-17-000 (May 13, 2010), p. 4; *Comment of the Federal Trade Commission*, Docket No. RM10-17-000 (May 13, 2010), p. 7; *Comments of ISO New England Inc*, Docket No. RM10-17-000 (May 13, 2010), p. 16; *Comments of Massachusetts Attorney General and*

considered is which DR entity FERC would regulate. For example, under the NOPR proposal presumably there would be certain large industrials dealing directly with the RTOs. However, there are also third-party DR providers that will aggregate multiple companies and sources. When a third party is involved, presumably the full LMP gets paid to the third party DR provider, while the actual consumer gets paid less than LMP How does that impact the analysis for full LMP? Are these third parties required to apply for and receive market-based-rate (MBR) authority, with the attendant market power tests? What is to prevent these entities from exercising market power unless they are also subject to the ISO/RTO mitigation measures? In addition to applying the rules and requirements to DR resources

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Maine Public Advocate, Docket No. RM10-17-000 (May 13, 2010), pp. 7-13; *Comments of the Midwest ISO Transmission Owners*, Docket No. RM10-17-000 (May 13, 2010), p.19; *Comments of Monitoring Analytics, LLC*, Docket No. RM10-17-000 (May 13, 2010), p.7; *Comments of New England Conference of Public Utilities Commissioners*, Docket No. RM10-17-000 (May 13, 2010), p.3; *Comments of the Northern California Power Agency*, Docket No. RM10-17-000 (May 13, 2010), p.3; *Comments of NSTAR Electric Company*, Docket No. RM10-17-000 (May 14, 2010), p.3; *Comments of D.C. Office of the People's Counsel*, Docket No. RM10-17-000 (May 13, 2010), p.5; *Comments of Old Dominion Electric Cooperative*, Docket No. RM10-17-000 (May 14, 2010), p.26; *Comments of PJM Power Providers Group*, Docket No. RM10-17-000 (May 13, 2010), p. 37; *Comments of Potomac Economics, Ltd.*, Docket No. RM10- 17-000 (May 13, 2010), p 4; *Comments of the PPL Parties*, Docket No. RM10-17-000 (May 13, 2010).

that are applied to generation, the Commission must explicitly address regulatory oversight surrounding these third parties as none of these elements are addressed in the NOPR and must be considered as part of the overall decision on whether to adopt the full LMP compensation proposal. EPSA and other commenters have concerns regarding the potential for gaming by DR under this proposal, as well as the potential for demand-side market power of a relatively small number of third party DR providers and the potential for abuse.[32]

Professor William Hogan addresses the implications for demand-side market power in his policy paper in this proceeding as follows:

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[32] ""Adverse selection" and "moral hazard" give market participants incentives to inflate baseline estimates and extract program payments for essentially normal consumption behavior. Under adverse selection, customers have the incentive to selectively join a demand response program just before the end of their peak usage season. The baseline would be established using load data compiled during the customer's high usage season, which allows the customer to receive demand reduction payments as the customer's load naturally begins to decline because the customer is transitioning into its off-peak season. Under moral hazard, customers may actively manipulate their load to create a higher-than-normal baseline and then receive payments for essentially normal consumption. Behavior associated with adverse selection and moral hazard was observed in the DALRP in the fall of 2007, which prompted changes to the program rules so as to limit the hours in which a demand reduction offer could clear under the program." Comments of ISO New England, pp. 32-33, Citations omitted, Docket No. RM10-17-000, (filed May 13, 2010) ("ISO-NE Comments").

> An argument has been made that the inefficiencies and cost increases for remaining consumers would be justified or avoided by achieving price reductions in LMPs that would reduce the total payments by consumers. For example, in the [now-terminated] PJM proceeding, Allen Freifeld provided an affidavit for the Demand Response Providers asserting that the imputed demand response program would provide a "price mitigation service to all load in the region" The price reduction argument misses the impact it would have on other aspects of the electricity market, most visibly in the case of organized RTO/ISO markets with explicit capacity requirements or markets. .
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> **In effect, this price mitigation service is not a policy to move towards a more competitive and efficient market. Rather, it would be an application of regulatory authority to enforce a buyers' cartel.** The price mitigation policy would not be improving efficiency. To the contrary, it would be employing government authority to transfer income from producers to consumers. **Thus the pursuit of price mitigation of this type would run contrary to the Commission's policy of supporting and facilitating efficient, non-discriminatory electricity markets.**[33] (Emphasis added.)

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[33] William W. Hogan, "Implications for Consumers of the NOPR's Proposal to Pay the LMP for All Demand Response," at

It is highly significant that the market monitors for all the ISOs/RTOs with DR programs available in their respective energy markets submitted comments raising serious concerns regarding the market inefficiencies and negative impacts of imposing a standardized one-size-fits-all approach to DR compensation without reducing load on the grid.[34] For example, the comments of the ISO-NE IMM also raise concerns regarding demand-side market power issues, including the potential for gaming by shifting load behind meters across multiple facilities while being paid DR subsidies.[35] The ISO-NE IMM notes,

> The full-LMP proposal also can present incentives for demand response providers, if they have energy-consuming facilities behind more than one meter, to shift load behind those meters to create illusory demand reductions. These incentives are

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12-13, Attachment 1 to the EPSA Initial Comments, Docket No. RM10-17-000, (filed May 12, 2010) (Hogan Paper).

[34] *See* Comments of the ISO New England Inc. Internal Market Monitor, pp. 5-7, Docket No. RM10-17-000, (filed May 13, 2010) (ISO-NE IMM Comments); *See generally* Comments of the Independent Market Monitor for PJM, Docket No. RM10-17-000, (filed May 13, 2010) (PJM IMM Comments); and, Comments of Potomac Economics, Ltd., pp. 9-10, Docket No. RM10-17-000, (filed May 13, 2010) (Potomac Economics Comments). Note that Potomac Economics serves as the External Market Monitor or the Independent Market Monitor (IMM) for the Midwest ISO, New York ISO, ISO New England, and ERCOT.

[35] ISO-NE IMM Comments, pp. 7-14, Docket No. RM10-17-000, (filed May 13, 2010).

> caused by the necessity to estimate what would have been consumed using an administratively determined customer baseline. **The use of such an administrative approach means that demand resource programs do not include a requirement for underlying ownership or property rights that typically serve as a foundation for a competitive market; that is, a competitive market for a good is premised on the voluntary exchange of a privately owned products, and therefore requires participants to own what they are selling.** The full-LMP approach does not require demand response providers to own the reductions they are selling, relying instead on the customer baseline as an estimate of what would have been used. One way that the use of an administrative baseline can be exploited is through unproductive load-shifting behind a customer's multiple meters to create illusory demand reductions Other load-shifting schemes likely exist.[36] (Emphasis added)

The ISO-NE IMM discusses a range of negative market impacts posed by the NOPR DR compensation proposal, including that a full LMP payment in all hours is economically inefficient, and results in preferential, non-comparable treatment of DR resources in relation to generating resources. Additionally, "The current proposal would also create incentives for customers to develop load-shifting arrangements and

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[36] Id., p. 11. Also, see Hogan Paper, pp. 7-12.

other schemes that would result in demand response that is not genuine."[37] The ISO IMM includes an Attachment to its comments to illustrate how customers can manipulate their operations in order to collect DR payments without actually reducing load at all. This load shifting strategy is not simply an operational choice about where to run operations, but it creates phantom DR which receives a payment, while the customer does not decrease its overall demand. The ISO-NE IMM concludes, "Other customers bear the burden of payments for the illusory demand reduction while the manufacturing company receives the payments at virtually zero opportunity costs."[38]

Among other things, the ISO-NE IMM recommends that, if the Commission permits a full LMP payment, it should also adopt a "buy-the-baseline" approach that would require the DR resource to purchase its expected amount of energy consumption in the day-ahead energy market (i.e., "buys the baseline") and sell any demand reduction from that level subsequently in the real-time market, essentially resulting in a compensation approach similar to LMP-G supported by numerous parties in this proceeding.[39] This approach, according to the ISO-IMM, also resolves the

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[37] ISO-NE IMM Comments, p. 4.

[38] ISO-NE IMM Comments, Attachment A, p. 2.

[39] Id., p. 12. Also, *see* Bushnell, Hobbs and Wolak, *"When it Comes to Demand Response, is FERC its Own Worst Energy?,"* The Electricity Journal, pp. 9-18 (October 2009).

concerns raised by reliance on an administratively set customer baseline.

3. FERC Should Focus On Addressing Barriers To Economic DR Development

The DR Supporters comments continue [from the PJM proceeding] to make a number of arguments (with a lack of support, other than referencing the NOPR) that can be boiled down to the general assertion that insufficient DR has resulted in diminished grid efficiency and market efficiency to the detriment of consumers. EPSA's prior comments both in this proceeding and the PJM proceeding have noted in detail the significant recent increases of DR participation in total across various ISO/RTO markets, including capacity markets, where DR resource participation has yielded significant levels of compensation. It cannot be ignored that the DR Supporters arguments in support of full LMP compensation to address these perceived inefficiencies is completely at odds with numerous comments filed in this proceeding, including those by a number of state commissions, market monitors, ISOs/RTOs, and other market participants, who correctly assert instead that the NOPR's compensation proposal raises many concerns regarding both diminished grid efficiency (with respect to reliability as addressed elsewhere herein) and market efficiency.

For example, the Midwest TDUs highlight that,

> Requiring RTOs to dismantle and re-configure existing demand response programs will truncate the demand response compensation experiment in RTO

> markets before meaningful results are in. Cutting short the development of the existing, regional compensation regimes for demand response may in fact stifle, rather than accelerate, the development of effective demand response. "[40]

Several states raised concerns regarding the inefficiencies to the market of the NOPR proposal, including the Organization of MISO States ("OMS") which noted the following: "The payment of the full LMP distorts consumer behavior and would result in inefficient decisions to curtail load. In addition, the subsidy would have to be recovered from non-participating customers."[41] PJM also raises concerns with the market inefficiencies posed by potential cost shifting under the NOPR proposal as follows:

> In order to avoid large wealth transfers from loads that do not engage in demand response activity to loads that do provide demand response, PJM believes that appropriate and efficient demand response compensation may require coordination between the Commission, [retail regulators], competitive retail suppliers, and other RTOs, and possibly action on the part of [retail regulators] and

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[40] Comments of the Midwest TDUs, pp. 19-29, Docket No. RM10-17-000, (filed May 13, 2010) ("Midwest TDUs Comments").

[41] Comments of the Organization of MISO States, p. 3, Docket No. RM10-17-000, (filed May 13, 2010) ("OMS Comments"). *Also see* Comments of the Illinois Commerce Commission, Docket No. RM10-17-000, (filed May 6, 2010) ("ICC Comments").

> competitive suppliers. Otherwise, if there is no coordination or supporting [retail regulatory] or competitive supplier action, as necessary, the payment of the incorrect amount of economic load response compensation may significantly and unnecessarily increase the total dollar amount that PJM will need to charge PJM Market Participants, result in large cost shifts among Market Participants, and/or distort otherwise efficient incentives in the wholesale energy market.[42]

As a further example, the PJM IMM discussed that it is incorrect to drive prices below competitive levels and stated,

> The most basic barrier to a fully functional demand side of the market is that not all customers are exposed to the actual incremental cost of energy. The assertion that demand side participants should be paid full LMP, regardless of their retail tariff rate, because the current approach of paying LMP minus G represents an intervention into retail rate design, cannot be correct. The entire demand side program exists only because of the disconnect between wholesale and retail rates. The assertion that the program should not account for the details of the retail rate design leads to the conclusion that there should be no demand side program at all.[43]

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[42] Comments of PJM Interconnection, LLC, pp. 8-9, Docket No. RM10-17-000, (filed May 13, 2010) ("PJM Comments").

[43] PJM IMM Comments, p. 5.

It is also important to provide a correction of the DR Supporters' comments, which reference that the PJM IMM "has consistently pointed out that the demand side of wholesale electricity markets in PJM is 'underdeveloped.'"[44] The PJM IMM certainly has made this statement in several SOM reports, as well as the report on Barriers to Demand Side Response in PJM required by Order No. 719. However, the context for the discussion that the demand side of wholesale electricity markets in PJM is "underdeveloped" is presented in these IMM reports in the context that this is due to retail market barriers to DR participation (i.e., the lack of dynamic pricing). EPSA submits this concern is reflected in the PJM IMM's comments in this proceeding and as noted above. There is no indication in the IMM reports or elsewhere that any lack of participation is due to actions by any ISO/RTO or market participant that directly or indirectly discourages participation in DR programs that "operate as a restraint of trade" as alluded to in the DR Supporters comments.[45]

Importantly, there are numerous commenters who raise the concern that the NOPR proposal will in fact interfere with or stifle retail dynamic price response

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[44] DR Supporters Comments, p. 14 and fn.32 (referencing the PJM IMM's State of the Market Reports for PJM for 2006-2009, as well as the Order No. 719-required report on Barriers to Demand Side Response in PJM).

[45] Id., pp. 30-32.

programs or other utility or state DR products.[46] The Illinois Commerce Commission states, "[A]s the value

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[46] *Comment of Robert Borlick*, Docket No. RM10-17-000 (May 13, 2010), p. 4; *Comments of the California ISO*, , Docket No. RM10-17-000 (May 13, 2010), p. 4; *Comments of Calpine Corporation*, Docket No. RM10-17-000 (May 13, 2010), p. 4; *Comments of Capital Power Corporation*, Docket No. RM10-17-000 (May 13, 2010), p. 6; *Comment of Constantine Gonatas of CPG Advisors Inc.*, Docket No. RM10-17-000 (May 13, 2010); *Comment of the Delaware Public Service Commission*, Docket No. RM10-17-000 (May 13, 2010), p. 2; *Comment of the Detroit Edison Company*, Docket No. RM10-17-000 (May 13, 2010), p. 4; *Comments of Dominion Resources Services, Inc.*, Docket No. RM10-17-000 (May 13, 2010), pp. 7-8; *Comment of Duke Energy*, Docket No. RM10-17-000 (May 13, 2010), p. 4; *Comments of Edison Electric Institute*, Docket No. RM10-17-000 (May 13, 2010), p. 22; *Comments of Exelon Corporation*, Docket No. RM10-17-000 (May 13, 2010), p. 4; *Comment of the Federal Trade Commission*, Docket No. RM10-17-000 (May 13, 2010), p. 8; *Comments of Illinois Commerce Commission*, Docket No. RM10-17-000 (May 6, 2010), p. 13; *Comments of ISO New England Inc. Internal Market Monitor*, Docket No. RM10-17-000 (May 13, 2010), pp. 5-6; *Comment of ISO/RTO Council*, Docket No. RM10-17-000 (May 13, 2010); *Comments of Midwest TDUs*, Docket No. RM10-17-000 (May 13, 2010), p.13; *Comments of Monitoring Analytics, LLC*, Docket No. RM10-17-000 (May 13, 2010), p. 5; *Comments of New England Conference of Public Utilities Commissioners*, Docket No. RM10-17-000 (May 13, 2010), p. 4; *Comments of the New England Power Generators Association*, Docket No. RM10-17-000 (May 13, 2010), p. 2; *Comments of the New York ISO*, Docket No. RM10-17-000 (May 13, 2010); *Comment of New York State Public Service Commission*, Docket No. RM10-17-000 (May 13, 2010); *Comments of Samuel Newell, Kathleen Spees, and Philip Q Hauser*, Docket No. RM10-17-000 (May 13, 2010); *Comments of D.C. Office of the People's Counsel*, Docket No. RM10-17-000 (May 13, 2010); *Comments of Old Dominion Electric Coop-*

of the subsidy increases, the state commission's likelihood of implementing time-differentiated retail rates decreases."[47] The Organization of MISO States reiterates,

> [I]t should be clear to the Commission that state commissions and LSEs have significant concerns that the potential costs for non-participating customers may exceed the benefits that ARCs can provide to their states and to participating customers. State commissions will have a significant disincentive to support the participation of ARCs in RTO energy markets and in their states if the proposed rule is adopted.[48]

> Implementing market structures that allow for the participation of ARCs should not include the establishment of inefficient price signals which distort demand response behavior and result in a cost

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erative, Docket No. RM10-17-000 (May 14, 2010), p. 6; *Comment of Organization of MISO States*, Docket No. RM10-17-000 (May 13, 2010), p. 4; *Comments of PJM Interconnection*, Docket No. RM10-17-000 (May 13, 2010), pp. 5-6; *Comment of Public Utilities Commission of Ohio*, Docket No. RM10-17-000 (May 13, 2010), p. 5; *Comment of Public Utilities Commission of the State of California*, Docket No. RM10-17-000 (May 13, 2010), pp. 9-10; *Comments of RRI Energy, Inc*, Docket No. RM10-17-000 (May 13, 2010), p. 2; *Joint Comments of Southern California Edison Company, Pacific Gas & Electric & San Diego Gas & Electric*, Docket No. RM10-17-000 (May 13, 2010), pp. 3-5.

[47] ICC Comments, p. 14.

[48] OMS Comments, p. 7.

> burden on other customers. Further, State Commissions and LSEs should not be forced to make expensive and complex changes to retail tariffs and billing systems in order to accommodate the participation of ARCs. This would likely result in State Commissions either taking action to "opt-out" or declining to "opt-in" under the provisions approved in Order 719-A.[49]

These concerns reflect two critical problems with the NOPR proposal for full LMP in all hours—that it overcompensates (or functions as a subsidy) one resource in the wholesale market and thereby distorts market results, and that the proposal misdirects the focus on eliminating barriers by attempting to create a wholesale "fix" to bridge infrastructure and retail pricing barriers (which pose much greater obstacles for most load entities, particularly for residential customers). The DR Supporters themselves note that even were the Commission to require multiples of full LMP for DR providers, this could still be insufficient compensation due to the existence of other barriers.[50] Interestingly, several state commissions and advocates make a similar case, but reverse the conclusion, instead expressing concerns that the full LMP in all hours proposal will negatively impact or stall efforts to

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[49] OMS Comments, p. 9.

[50] DR Supporters Comments, p. 31.

implement dynamic pricing at the utility or state level.[51]

> The ISO-NE IMM notes,
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> [E]ach state has a different set of factual circumstances informing the decision on the need to provide extra incentives for demand response. As noted earlier, California has started on the road to dynamic pricing. Many states have taken significant steps to implement advanced meters and have implemented programs to encourage efficient use of energy. The success of these efforts should be a factor in deciding whether and how to implement demand response programs in the wholesale market.[52]

Importantly, this concern is bolstered by the recent issuance of the National Action Plan on Demand Response by the Commission on June 17, 2010. This report represents an extensive effort by the Commission staff and a plethora of stakeholders representing every type of interest to craft a plan that supports local, state and regional efforts to develop all manner of demand response programs and products as Congress intended. The report indicates the level of interest, effort and resources focused on developing local DR, and the importance of assessing costs and benefits in

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[51] See Footnote 45 above.

[52] Comments of the ISO-NE IMM, p. 6.

order to do so.[53] Numerous commenters, including state commissions and consumer advocates, raised concerns that this NOPR would in fact erect a barrier to those efforts. APPA and NRECA reiterate the need to preserve local and regional DR programs,

> In the NOPR, the Commission appears to divert from the broad and inclusive approach of the proposed National Action Plan, by prescribing one method of compensation for demand response that bids into RTO-run wholesale energy markets. APPA and NRECA, however, support allowing local and regional differences to be reflected in pricing rules in RTO-run markets.[54]

> In general, demand response rules in RTO-run markets have evolved to meet specific needs. Local and regional conditions largely determine what form and what compensation level for demand response is appropriate. The availability of particular resources in a particular region can mean that different compensation levels are needed to optimize the development of demand response. Varying consumer load profiles and retail market

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[53] See *National Action Plan on Demand Response generally*, also p 67 on valuating costs and benefits specifically.

[54] *Comments of the American Public Power Association and the National Rural Electric Cooperative Association*, Docket No. RM10-17-000 (May 13, 2010), p. 3. (APPA/NRECA Comments)

structures dictate that different compensation levels are appropriate in different RTO-run markets.[55]

Another concern in the context of assessing increased DR participation in the wholesale markets is the DR "saturation" issue with respect to grid efficiency and reliability impacts to the system if such resources are not available to perform when called, particularly given that such resources are not currently subject to the same rules and requirements as supply resources. Accordingly, EPSA recommends that, among other things, the Commission should take expeditious action to address identified barriers to development of DR resources and encouraging the transition to price responsive demand (PRD) resources. Several RTOs, including CAISO, NYISO, PJM and ISO-NE have such PRD stakeholder initiatives, which have been underway for some time now, though some appear to have been slowed pending the outcome of this NOPR.

B. WHILE ONE MEGAWATT OF DEMAND IS NOT EQUAL TO ONE MEGAWATT OF SUPPLY, FOR PURPOSES OF ALLOWING DR TO BID IN TO ENERGY MARKETS AS A "COMPARABLE" RESOURCE ALL MARKET RULES, MITIGATION, OBLIGATIONS AND REQUIREMENTS MUST APPLY TO DR AS WELL AS TO SUPPLY

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[55] APPA/NRECA comments, pp. 11-12.

As EPSA stated in its May 12 comments, one megawatt of demand is not equal to one megawatt of traditionally generated supply. The Commission's policy is comparability, and it is important to note the distinctions between the two resource types in order to achieve actual comparability. Within the comments filed on the NOPR, the comparability debate has divided into three categories—the nature of demand response as a balancing resource, the dispatchability of demand response, and a demand response product's obligations as a market participant in organized wholesale electric markets. APPA and NRECA aptly summarize a widely held understanding of how DR should be treated in energy markets:

> It is not unjust and unreasonable to treat demand response resources differently than generators and other suppliers. By analogy to Order No. 890, demand response, generation and transmission are to be treated "comparably," but it does not follow that each of them is "the same" and therefore must be compensated in the same manner.[56]

Additionally, the Illinois Commerce Commission includes a graphic economic analysis to support the difference between supply and demand as resources.

> In pure economic terms a reduction in demand is fundamentally different from an increase in supply. Demand reductions and supply increases are not

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[56] APPA/NRECA Comments, pp. 12-13.

only intuitively divergent, but treating them equivalently has material implications. Graphical depictions will be used to illustrate how demand reductions and supply increases affect the dispatch model and result in different market outcomes.' The ICC believes that demand response should be incentivized and participants should be fairly compensated, but these comments show that they are not particularly comparable with generation supply.[57] (Citation omitted.)

1. IF DR IS A BALANCING SERVICE IT SHOULD BE TREATED AND COMPENSATED AS A SERVICE, NOT AS SUPPLY

Even supporters of the Commission's proposal have admitted to varying degrees that the physical abilities of demand response are different from those of generation resources. Some commenters have spoken generally and rhetorically about demand response, as if it were all one product type, seeming not to notice that the Commission's proposal targets economic, non- emergency demand response.[58] Other commenters have conceded that some demand response resources are controllable and callable while others are not.[59] Regardless of the degree to which

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[57] ICC Comments, p. 2 See graphic models as verified by Nicholas Bowden, Economic Analyst, Federal Energy Program, ICC.

[58] *See* Viridity Initial Comments and CDRI Comments.

[59] DR Supporters Comments, p. 20, "On the load side of the balancing equation, some loads will be relatively inflexible and uncontrollable. Other forms of load can be controlled—by the grid operator or the customer—in response to price."

supporters of the NOPR's proposal understand various demand response products, they largely seem to agree on one thing—that demand response is a balancing service.

The Consumer Demand Response Initiative ("CDRI") notes that "a reduction in consumption is comparable to an increase in production for the purpose of balancing supply and demand *at the margin*."[60] The joint public interest organizations ("PIO") assert that "a reduction in energy consumption meets essential system needs, including load balancing and resource adequacy."[61] Demand Response Supporters state that, "flexible and price-responsive demand that can reduce the supply requirements required for balance has the equal impact of reducing the marginal price of achieving a reliable and balanced grid."[62] The types of benefits they say that price-responsive demand produces are similar, if not equal to, other balancing products that operate in Ancillary Services Markets.

> The Demand Response Supporters extrapolate from their discussion that,
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> [P]roviding additional generation and curtailing consumption effectively provide the same service to the market, [therefore] it is crucial that the Com-

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[60] CDRI Comments, p. 10. (Emphasis added.)

[61] *Corrected* Joint Comments of Public Interest Organizations On Notice of Proposed Rulemaking (NOPR), p. 4, Docket No. RM10-17-000, (filed May 14, 2010) ("PIO Comments").

[62] DR Supporters Comments, p. 9.

> mission provide compensation to demand-side resources that is comparable to compensation for generation—i.e., full LMP in today's markets.[63]

However, balancing services have wholly different compensation algorithms from generation resources. In most markets, a balancing service is assigned a value by the stakeholder process, its compensation is agreed upon, finalized in a tariff proposal and ultimately subject to approval by the Commission. These services usually are compensated relative to opportunity costs. PJM, ISO-NE, MISO, NYISO and ERCOT all have fully functioning ancillary services markets that buy and sell balancing services to the grid.[64] Certainly providers of ancillary services are important to the maintenance and improvement of the reliability of the system and require ***appropriate*** compensation. However, that compensation is not a direct reflection of the supply of electricity as demand response bids cannot abide by all of the parameters and requirements of supply (see section on market obligations below). Therefore, an option for an appropriate compensation mechanism for price responsive demand should reflect and be developed in a manner similar to other products in the ISO/RTO

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[63] Id., p. 22.

[64] For examples of how different values are placed on differing products, see: *A Review of Generation Compensation and Cost Elements in the PJM Markets* (2009), available at: http://www.pjm.com/~/media/committees-groups/committees/mrc/20100120/20100120-item-02-review-of-generation-costs-and-compensation.ashx.

ancillary services markets, which would likely vary by region as do other ancillary service payment levels.

2. TO BE COMPARABLE, DR MUST BE DISPATCHABLE

A major element of the comparability argument in this proceeding has been the dispatchability of demand response resources, and how these resources affect the economic dispatch of the system. Some supporters of the NOPR refer to economic DR as "controlled" or "actively managed" load, but that control and management is by the DR provider.[65] As discussed in the NOPR and supporting comments, DR economic bids are entirely voluntary,[66] and there is no regulatory language or explanation in the NOPR as to the important question of how economic DR is accepted or dispatched by the market operator. EPSA's initial comments touched on the fact that most DR resources are technically incapable of acting as traditional dispatchable supply. A plethora of commenters not only agreed with EPSA, but expanded on why demand response is not the same as an energy product in technical terms.[67]

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[65] Viridity Reply Comments, pp. 3, 6 and generally.

[66] *Reply Statement of Audrey Zibelman, regarding Reply Comments of Viridity Energy, Inc.*, Docket No. RM10-17-000 (June 18, 2010), p. 11. "The economic decision that the customer uses to dispatch these resources is complex and requires algorithmic based calculus, system understanding and contingency analysis *to produce the desired economic outcome.*" (Emphasis Added).

[67] For examples, see: EEI, p. 15; P3, pp. 2-3; Monitoring Analytics, p. 5; NYISO, p. 3; PJM, p. 6; ISO-NE, p. 18-19; PJM Power Providers, Tranen affidavit, p. 2-3; Borlick Comments, p. 4.

In its comments, ISO New England raised another dispatchability concern—the possibility for preferential dispatch of high cost demand response resources over lower cost generation resources. As the independent market administrator, ISO New England is apprehensive that paying full LMP to demand responders will produce a more expensive resource, as the demand responder is also experiencing cost-savings in its energy bill plus any incentive payments from the regional wholesale market. Thus, because generation resources experience no such savings and are paid the same LMP price, the proposed rule will dispatch higher-cost demand resources. "By dispatching higher-cost demand resources, lower-cost generating resources are displaced, which is inefficient and increases the total resource costs in the energy market," ISO-NE concluded.[68] The Brattle Group echoes this concern:

> At a wholesale level, the economically efficient level of compensation for load reductions (not load shifts) is the LMP minus the avoidable generation portion of the retail rate, resulting in a net savings equal to the LMP. The efficient compensation for any load that shifts from one hour to another is the LMP difference between the two hours. Providing more would distort incentives and lead to inefficient system dispatch.

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[68] ISO-NE Comments, p. 3.

> Any higher compensation, including compensation at the full LMP, represents a subsidy for DR that could distort market incentives, resulting in inefficient load management and inefficient dispatch of behind-the-meter generation. This incentive distortion could be particularly problematic if instituted in markets with mature DR penetration.[69]

ISO-NE and the Brattle Group have highlighted an important point. Not only does it incorporate the economic principles espoused by Dr. Hogan in EPSA's initial comments, but it also relates to Dr. Hogan's arguments regarding market operation and comparability issues. There is a fundamental market design flaw that will emerge if the NOPR's proposal is allowed to go forward—competitive markets designed to dispatch the lowest-cost supply first will no longer be able to do so because it is not clear from the NOPR that DR is dispatched as part of the supply stack. EPSA will not reiterate all of ISO-NE's arguments in these reply comments; however, the nexus that ISO-NE has found between Dr. Hogan's economic arguments speaks to the very essence of the competitive market structure. If the NOPR's proposal is allowed to go forward, that structure that seeks to dispatch the lowest cost supply first will be compromised. EPSA agrees with ISO-NE's assessment and urges the Commission to consider the negative effects the

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[69] *Comments of Samuel Newell, Kathleen Spees, and Philip Q Hanser*, Docket No. RM10-17-000 (May 13, 2010), pp. 2-3, p. 8.

NOPR proposal will have on competitive market structures. In fact, this argument negates the proposition from those who support the NOPR that the proposal will bolster competition. EPSA agrees with ISO-NE that the NOPR proposal will harm competitive market practices, particularly security-constrained economic dispatch in which low cost supply is called upon first.

C. ANY RULE ON DR COMPENSATION MUST ADDRESS CONCERNS OVER MEASURABILITY AND VERIFICATION AND SHOULD REFLECT SUGGESTED CHANGES TO INCLUDE AN OFFSET AND/OR THRESHOLDS FOR PARTICIPATION

Striking among comments was the recurrent call from numerous types of stakeholders for several changes that must be made to the compensation mechanism or included in any final rule in order to ensure that the resulting compensation methodology and the role of economic DR in the ISOs/RTOs is beneficial both to the efficiency and operation of the market and broadly to consumers in the end. These required changes address two primary areas: the compensation methodology itself, and what must be addressed in addition to compensation in order for the rule to function rationally. As to the compensation methodology, many stakeholders echoed EPSA's concern that the full LMP proposal does not reflect any offset to represent the purchase of energy, as should be required to enable a sale of energy back to the system. Additionally, numerous commenters raised concerns that the compensation as proposed would apply in all hours rather than in those times when

needed and called by the system. This notion leads to the next basket, in that the pricing proposal for all hours raises concerns about how customer baselines would be assessed and managed, which is tied in to the oft repeated request that the issues of measurability and verification must be addressed at least in tandem with if not in advance of imposing any uniform compensation methodology. Additionally, as payment of full LMP in all hours will create additional costs that must be paid to DR providers by customers unable to leave the grid, how costs related to DR compensation are allocated (e.g., within each LSE, across the entire ISO/RTO, etc.) was an important concern among several commenters, yet not addressed in the NOPR.

1. The Economically Efficient Price for DR Reflects an Offset for the Purchase of Energy

While numerous commenters characterized the economically efficient and proper price for economic DR in different ways, there was basic agreement across a wide array of stakeholders that there must be an offset to reflect the avoided cost, or the purchase of, the energy that the DR provider is not taking from the system.[70] The Organization

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[70] *Comment of American Electric Power Service Corporation*, Docket No. RM10-17-000 (May 13, 2010); *Comments of the American Public Power Association and the National Rural Electric Cooperative Association*, Docket No. RM10-17-000 (May 13, 2010); *Comment of Battelle/Pacific Northwest Laboratories*, Docket No. RM10-17-000 (May 13, 2010); *Comment of Robert Borlick*, Docket No. RM10-17-000 (May 13, 2010); *Comments of Calpine Corporation*, Docket No. RM10-17-000 (May 13, 2010); *Comments of Capi-*

tal Power Corporation, Docket No. RM10-17-000 (May 13, 2010); *Comment of Consolidated Edison Energy, Inc., et. al*, Docket No. RM10-17-000 (May 13, 2010); *Comment of Constantine Gonatas of CPG Advisors Inc.*, Docket No. RM10-17-000 (May 13, 2010); *Comments of Dominion Resources Services, Inc.*, Docket No. RM10-17-000 (May 13, 2010); *Comment of Duke Energy*, Docket No. RM10-17-000 (May 13, 2010); *Comments of Edison Electric Institute*, Docket No. RM10-17-000 (May 13, 2010); *Comments of Edison Mission Energy*, Docket No. RM10-17-000 (May 12, 2010); *Comments of Exelon Corporation*, Docket No. RM10-17-000 (May 13, 2010); *Comment of the Federal Trade Commission*, Docket No. RM10-17-000 (May 13, 2010); *Comments of GDF Suez Energy North America, Inc.*, Docket No. RM10-17-000 (May 13, 2010); *Comments of Illinois Commerce Commission*, Docket No. RM10-17-000 (May 6, 2010); *Comment of Independent Power Producers of New York, Inc.*, Docket No. RM10-17-000 (May 13, 2010); *Comments of the Indicated New York Transmission Owners*, Docket No. RM10-17-000 (May 13, 2010); *Comment of International Power America, Inc.*, Docket No. RM10-17-000 (May 14, 2010); *Comments of ISO New England Inc*, Docket No. RM10-17-000 (May 13, 2010); *Comments of ISO New England Inc. Internal Market Monitor*, Docket No. RM10-17-000 (May 13, 2010); *Comment of ISO/RTO Council*, Docket No. RM10-17-000 (May 13, 2010); *Comment of Midwest Independent System Transmission Operator, Inc.*, Docket No. RM10-17-000 (May 13, 2010); *Comments of the Midwest ISO Transmission Owners*, Docket No. RM10-17-000 (May 13, 2010); *Comments of Midwest TDUs*, Docket No. RM10-17-000 (May 13, 2010); *Comments of Mirant Corporation*, Docket No. RM10-17-000 (May 13, 2010); *Comments of Monitoring Analytics, LLC*, Docket No. RM10-17-000 (May 13, 2010); *Comments of the New England Power Generators Association*, Docket No. RM10-17-000 (May 13, 2010); *Comments of the New York ISO*, Docket No. RM10-17-000 (May 13, 2010); *Comment of New York State Public Service Commission*, Docket No. RM10-17-000 (May 13, 2010); *Comments of Samuel Newell, Kathleen Spees, and Philip Q Hauser*, Docket No.

of MISO States, representing over 40 million electricity customers in 14 states, noted,

> An "efficient" payment to the retail customer is the amount necessary to provide sufficient incentive for customers to make consumption decisions as if they were facing the wholesale rate and thus not to exercise their option to purchase at the lower retail rate. The question at hand becomes: How much does the retail rate have to be increased so that retail customers behave as if they are facing the wholesale LMP? Because the retail customer is already facing the retail rate, the efficient payment is represented by the difference between the LMP and the retail rate.[71]

Importantly, OMS continues,

RM10-17-000 (May 13, 2010); *Comments of Northeast Utilities Service Company*, Docket No. RM10-17-000 (May 13, 2010); *Comments of the Northern California Power Agency*, Docket No. RM10-17-000 (May 13, 2010); *Comments of Old Dominion Electric Cooperative*, Docket No. RM10-17-000 (May 14, 2010); *Comment of Organization of MISO States*, Docket No. RM10-17-000 (May 13, 2010); *Comments of PJM Interconnection*, Docket No. RM10-17-000 (May 13, 2010), pp. 6-8; *Comments of Potomac Economics, Ltd.*, Docket No. RM10-17-000 (May 13, 2010); *Comments of the PPL Parties*, Docket No. RM10-17-000 (May 13, 2010); *Comments of the PSEG Companies*, Docket No. RM10-17-000 (May 13, 2010); *Comment of Public Utilities Commission of Ohio*, Docket No. RM10-17-000 (May 13, 2010); *Comments of RRI Energy, Inc*, Docket No. RM10-17-000 (May 13, 2010); *Comments of Southwest Power Pool, Inc.*, Docket No. RM10-17-000 (May 13, 2010).

[71] OMS Comments, p. 3.

> The payment of any amount in excess of this difference to the ARC, such as the full LMP, would result in a "distortionary subsidy" to the retail customer and the ARC. The concept that the payment of the full LMP to ARC's is inefficient and would result in market distortions is well-known has been discussed in various reports and in comments to the Commission in other proceedings.4 The payment of the full LMP distorts consumer behavior and would result in inefficient decisions to curtail load. In addition, the subsidy would have to be recovered from non-participating customers. It is clear that the proposed rule would replace one inefficient price signal with a different inefficient price signal and would result in a subsidy to ARCs and participating customers.[72]

While the OMS notes that the Commission's compensation proposal could be corrected at the state level to represent an efficient price signal and price, this correction would be complicated and possibly legally difficult. Instead, this can be more simply resolved by setting a wholesale compensation formula which subtracts the retail rate from the LMP for payments to Aggregators of Retail Customers ("ARCs"). This sentiment is echoed by the Illinois Commerce Commission,[73] which through detailed economic analysis

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[72] Id.

[73] Ironically, some of the parties who insist most vociferously that the Commission does have jurisdiction over DR as a "service [that] is rendered in the wholesale market," (Reply Comments of Viridity,

and modeling supports that the payment of LMP minus the retail rate, "makes the load serving entity indifferent between the consumption of another unit of electricity and the consumption of a unit of demand response. Correctly aligning the load serving entity's incentives with the desired behavior is an integral part of accomplishing any policy objective."[74]

In another approach to achieve the same rational and efficient economic result, the ISO-New England explains that, "Comparability and symmetry are achieved by netting out the bill savings from the full LMP payment made to a demand response provider

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p. 3), take a much narrower view of the Commission's jurisdiction when discussing offsets to DR compensation to account for avoided retail rates. For example, Viridity claims that such proposals "seek to draw the Commission into a review of retail rate matters beyond the Commission's jurisdiction." *Id.* at 13. As EPSA previously explained in response to similar objections to PJM's LMP-G proposal, parties seeking to have the Commission assert jurisdiction over DR compensation while averting its gaze from avoided retail charges are attempting to have it both ways and ignoring the fact that the Commission is not purporting to set the retail rate (*i.e.*, "G") but instead is using that rate, as determined by state regulators, as an input to a wholesale rate formula. *See* Motion for Leave to Answer and Answer of the Electric Power Supply Association and White Paper by Professor William W. Hogan, pp. 11-17, Docket No. EL09-68-000 (filed Oct. 30, 2009). In any event, the fact that state regulators, including the Illinois Commerce Commission and the members of OMS, filed comments supporting the LMP-G illustrates that this approach does not infringe upon state jurisdiction.

[74] ICC Comments, p. 13.

for demand reductions, for demand resources that have reduced consumption relative to an estimated baseline."[75] In order to achieve this comparability, ISO-NE states that DR can either be paid LMP-G, or,

> [I]f the objective is payment of the full LMP in all hours in which the consumption of electricity was reduced from expected levels in response to price signals, then the day-ahead purchase of expected energy use, or some other advance purchase requirement, should be required. This is efficient, avoids the need for an estimated baseline, and avoids the need to allocate costs of payments to demand resources.[76]

The FTC summarizes,

> We question the soundness of a policy that would pay companies the proceeds from the sale of power that they never bought in the first place. Such a policy would create situations in which a demand response provider would find it more profitable to sell its power rights (*i.e.*, provide demand response) than to consume that power, even though the value to society of consuming that power exceeds the power's cost to society.[77]

Essentially, if there is not an offset for avoided cost (or retail charge), there should be an actual purchase

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[75] ISO-NE Comments, pp. 3-4.

[76] ISO-NE Comments, p. 5.

[77] FTC comments, p. 2.

requirement for expected energy use in the Day Ahead market. This proposal is echoed by the ISO-New England Internal Market Monitor, which refers to this as a "buy the baseline" approach.[78] This approach also resolves concerns over inauthentic or manipulated DR baselines.

Additionally, it is important to note that the NYISO and CAISO, characterized as currently paying full LMP to DR, are in special circumstances as one state, one utility commission, one ISO markets. For instance, while the California investor-owned utilities support the NOPR as some DR supporters stress, those utilities also clarify that the retail jurisdictional entity will adjust compensation as necessary through retail revenue settlements, which for CAISO is just one regulatory body. While characterized as supporters of the NOPR, the California utilities actually state,

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[78] "A modification to the Commission's proposal based on requiring ownership of the energy reduction sold into the market by the demand resource provider would permit the payment of full LMP to demand response providers consistent with economic efficiency. This approach, referred to herein as "buying the baseline," requires a demand response provider to purchase its expected amount of demand reduction in the day-ahead energy market in order to be paid full LMP in the real-time energy market. The advantage of the buy-the-baseline approach is that it can be implemented by the Commission without changes in state policies." ISO-NE IMM Comments, p. 4.

> Adjustments to the full LMP compensation will be necessary given the potential for a retail customer to be overpaid if it receives compensation for reducing its load via wholesale markets and also benefits from bill savings on its retail tariffs. As with under-compensation, over-compensation of DR will send an incorrect price signal and result in market inefficiency.

This factual difference is important in understanding the comments and programs in place in both California and New York, as compensation will be adjusted to reflect a retail offset, thus reaching the same result EPSA advocates.

2. The Proposal to Pay Full LMP in All Hours Creates Operational and Economic Concerns

Similar to the reaction to the payment of full LMP with no sort of offset for a purchase or obligation, there was a wide array of opposition to the proposal to pay DR market prices in all hours at all times.[79] The

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[79] *Comment of American Electric Power Service Corporation*, Docket No. RM10-17-000 (May 13, 2010), pp. 9-10; *Comments of the American Public Power Association and the National Rural Electric Cooperative Association*, Docket No. RM10-17-000 (May 13, 2010), p. 14; *Comments of Capital Power Corporation*, Docket No. RM10-17-000 (May 13, 2010), p. 5; *Comment of Constantine Gonatas of CPG Advisors Inc.*, Docket No. RM10-17-000 (May 13, 2010), pp. 9-10; *Comments of the Indicated New York Transmission Owners*, Docket No. RM10-17-000 (May 13, 2010), p. 5; *Comments of ISO New England Inc*, Docket No. RM10-17-000 (May 13, 2010), pp. 28-29; *Comments of Massachusetts Attorney General*

concerns reflect the operational impacts created by the economic incentive to reduce demand during non-peak, low stress periods. Largely this is manifested in whether and how DR baselines for expected consumption can be accurately established and frequently updated. Additionally, payment of full LMP to DR during many hours will not result in net benefits to customers, as the DR payments will be substantially more than the savings created by reducing the clearing price at that time. Therefore, numerous commenters suggest that LMP payments be limited to those hours in which net benefits will be realized by a broad class of all consumers generally.

On the operational concerns, New England Public Systems, representing cooperatives in Connecticut, Massachusetts and New Hampshire, explains that based on extensive experience detailed in its comments,

> [Opposition to the mandate in the NOPR] is premised upon our region's hard-earned experience attempting to integrate demand response resources

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and Maine Public Advocate, Docket No. RM10-17-000 (May 13, 2010), pp. 7-11; *Comments of National Grid USA*, Docket No. RM10-17-000 (May 13, 2010), pp. 3-6; *Comments of New England Conference of Public Utilities Commissioners*, Docket No. RM10-17-000 (May 13, 2010), p. 3; *Comment of New York State Consumer Protection Board*, Docket No. RM10-17-000 (May 13, 2010); *Comment of New York State Public Service Commission*, Docket No. RM10-17-000 (May 13, 2010), p. 10; *Comments of NSTAR Electric Company*, Docket No. RM10-17-000 (May 14, 2010).

> in a day-ahead load-response program that paid DR resources the full LMP under certain conditions: an attempt that—because of poorly defined baselines—ended up paying millions of dollars for "demand response" that failed to represent a real departure from normal operations.[80]

Additionally, ISO-NE explains,

> The proposed rule also introduces baseline estimation and cost allocation problems, neither of which is addressed in the NOPR and both of which must be fully addressed before any final rules can be issued. The Commission's proposed requirement that those who reduce consumption of electricity from *expected levels* in response to price signals be paid the full LMP for such reductions *in all hours* creates a situation in which baseline estimation becomes a substantial challenge. There is no baseline estimation technique that can accurately and reliably estimate what a customer's energy usage pattern would have been if that customer responds frequently to price signals.[81]

The New England Public Systems explain that they are troubled by the LMP in all hours approach as it

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[80] *Comments of Connecticut Municipal Electric Energy Cooperative, Massachusetts Municipal Wholesale Electric Company, and New Hampshire Electric Cooperative, Inc.* (Collectively, "New England Public Systems"), pp. 1-2.

[81] ISO-NE Comments, p. 4, emphasis reproduced as appears in comments.

"appears to do away with minimum offer requirements that the Commission previously found to be necessary to guard against abuse, without proposing an alternative baseline-setting mechanism to prevent such abuse."[82] The issue of developing useful, accurate baselines permeated many of the comments, and clearly requires careful attention in any final rule that would establish a compensation mechanism for economic DR.[83]

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[82] New England Public Systems Comments, Docket No. RM10-17-000 (May 13, 2010), p. 15.

[83] *Comment of American Electric Power Service Corporation*, Docket No. RM10-17-000 (May 13, 2010), p. 12; *Comments of Connecticut Municipal Electric Energy Cooperative, Massachusetts Municipal Wholesale Electric Company, and New Hampshire Electric Cooperative, Inc.* Docket No. RM10-17-000 (May 13, 2010), pp. 7-14; *Comments of Dominion Resources Services, Inc.*, Docket No. RM10-17-000 (May 13, 2010), p. 7; *Comments of Edison Electric Institute*, Docket No. RM10-17-000 (May 13, 2010), p. 19; *Comment of the Federal Trade Commission*, Docket No. RM10-17-000 (May 13, 2010), p. 8; *Comment of Illinois Citizens Utility Board*, Docket No. RM10-17-000 (May 13, 2010), pp. 16-17; *Comments of the Indicated New York Transmission Owners*, Docket No. RM10-17-000 (May 13, 2010), p. 3; *Comments of ISO New England Inc*, Docket No. RM10-17-000 (May 13, 2010), pp. 31-36; *Comment of the Joint Consumer Advocates*, Docket No. RM10-17-000 (May 13, 2010), p. 12; *Comment of Joint Public Interest Organizations*, Docket No. RM10-17-000 (May 13, 2010), at fn. 2; *Comments of the Midwest ISO Transmission Owners*, Docket No. RM10-17-000 (May 13, 2010), p. 13; *Comments of Midwest TDUs*, Docket No. RM10-17-000 (May 13, 2010), p. 11; *Comments of National Grid USA*, Docket No. RM10-17-000 (May 13, 2010); *Comments of New England Conference of Public Utilities Com-*

Even among some commenters that support the payment of full LMP with no offset, there remain concerns that in many hours that payment will not yield net benefits to the system. Therefore, numerous commenters representing varied stakeholder sectors support the establishment of some measurable threshold or trigger to ensure that market prices are paid to DR providers when there will be an economic net benefit for consumers. The New York State Consumer Protection Board ("NYSCPB") noted, "[P]ayment of LMP to DR resources should apply to all hours when the net benefit to customers is positive. DR provides net benefits to customers as long as they reduce energy costs (through lower energy prices) by an amount that exceeds the costs of DR."[84] The NYSCPB recommends that individual ISO/RTOs de-

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missioners, Docket No. RM10-17-000 (May 13, 2010), p. 3; *Comments of the New England Power Generators Association*, Docket No. RM10-17-000 (May 13, 2010), attachment p. 26; *Comments of the New York ISO*, Docket No. RM10-17-000 (May 13, 2010), p. 8; *Comments of Occidental Chemical Corporation and Occidental Permian Ltd.*, Docket No. RM10-17-000 (May 13, 2010), p. 2; *Comments of the Pennsylvania Public Utilities Commission*; Docket No. RM10-17-000 (May 13, 2010), p. 1; *Comments of PJM Power Providers Group*, Docket No. RM10-17-000 (May 13, 2010), p. 38; *Comment of Public Utilities Commission of Ohio*, Docket No. RM10-17-000 (May 13, 2010), p. 5; *Comments of RRI Energy, Inc*, Docket No. RM10-17-000 (May 13, 2010), p. 6; Comments of Southwest Power Pool, Inc., Docket No. RM10-17-000 (May 13, 2010), pp. 3-4; *Comment of Westar Energy, Inc., et. al.*, Docket No. RM10-17-000 (May 13, 2010), p. 3.

[84] NYSCPB comments, p. 4.

velop and implement the tools to assess whether a net customer benefit would occur. The Illinois Citizens Utility Board also states, "Full LMP compensation should only be paid to demand resources that intentionally and directly reduce energy usage in response to the market price. Stated differently, only if the demand response truly avoids costs on the system should it be compensated."[85]

The New England Consumer Advocates (the Massachusetts Attorney General and Maine Public Advocate) echo both this concern and recommendation—that the regions develop participation threshold mechanisms that ensure LMP payments are made when it is cost effective for ratepayers. They state,

> Although demand response resources that clear as supply-side resources should be compensated at full LMP, allowing them to clear in all hours, as the Commission proposes, may lead to situations where the total cost paid by load actually increases as a result of demand response participation.[86]

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[85] Illinois Citizens Utility Board, p. 19. Citation omitted.

[86] New England Consumer Advocates, p. 11. Citation omitted. Of note, this filing points to an example threshold mechanism developed by Consumer Demand Response Initiative ("CDRI") that utilizes a dynamically-set algorithm that would allow a demand response resource bid to clear only if it reduces the clearing price more than it increases the cost to load due to the decreased demand.

Additionally, the New England Conference of Public Utility Commissioners ("NECPUC"), representing the commissions in six states, explains,

> While NECPUC supports improving competitiveness of the organized wholesale energy market by eliminating barriers to participation for demand response resources, the principle of providing net benefits to customers must be considered when considering the hours in which demand response resources are compensated. Providing incentives for demand response resources in all hours, as the Commission proposes, may not result in net benefits to all market customers.[87]

> Demand response resources have the capability to benefit consumers by lowering clearing prices when more expensive resources are displaced. Conversely, supply-side treatment for demand response resources may also raise costs. Demand response resources provide net benefits when the positive benefits from lower clearing prices outweigh the price increase resulting from supply-side treatment. Thus, NECPUC respectfully submits that demand response resources should be provided an incentive to participate in organized wholesale energy markets when they provide net economic benefits to all market customers, including

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[87] NECPUC Comments, p. 9.

those who provide demand resources and those who do not.[88]

NECPUC supports payment of full LMP, but explains in detail the relationship between supply and demand reduction for the supply stack and dispatch, and why demand reduction during the highest-priced hours of the year results in clearing price reductions that offer net benefits to demand. However, demand response at times when the supply curve is not very steep may not adequately reduce the clearing price. "[T]he Commission's proposal to compensate demand response resources with the market price in all hours may increase costs to customers in some circumstances and this may be unjust and unreasonable."[89] For this reason, NECPUC recommends that each ISO/RTO develop a price threshold mechanism that ensures net benefits. NECPUC uses a threshold based on a dynamic floor price for eligibility, which is equal to the product of a fuel price index and a heat rate from a representative marginal generation resource.[90] NECPUC's comments are just an example of one type of threshold mechanism that could be developed at a regional level.

3. The Proposal Does Not Address Concurrent Development of Measurement and Verification Tools and Requirements

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[88] NECPUC Comments, p. 10.

[89] NECPUC Comments, p. 14-17 with graphic illustrations.

[90] Id., p. 19.

Another widely established concern is that the NOPR does not address the accurate measurement and verification ("M&V") of DR participation in the energy markets. While such tools are being discussed and under development currently, it is critical that they are implemented in direct relationship to a standardized compensation mechanism for economic DR. This consideration is emphasized in the recently issued National Action Plan for Demand Response, which noted,

> Finally, development of measurement and verification standards is critically needed at both the wholesale and retail levels. Methods for measuring and verifying demand response reductions currently vary significantly across the country, and measurement and verification standards will increase confidence in markets The efforts of NAESB and NERC should provide valuable tools and standardization to ensure that demand response is accurately measured and verified.[91]

However, with no discussion or inclusion of such tools, the NOPR seeks to pay for something that is neither measured nor verified based on the parameters of the NOPR proposal. The Illinois Citizen Utility Board noted,

> A lack of stringent measurement and verification can result in compensating demand resources when

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[91] National Action Plan on Demand Response, pp. 66-67.

> no verifiable usage reduction took place, or when a usage reduction occurred for reasons other than in response to the market price. Such occurrences can undermine the credibility and ultimately the viability of demand response programs.[92]

Additionally, Joint Consumer Advocates ("JCA") representing four state consumer advocates in ISO-NE, PJM and Midwest-ISO, states,

> JCA wishes to make clear that while it supports the broad deployment of demand response by way of compensation at full LMP, it also supports the responsible deployment of demand response through the establishment and enforcement of rigorous M&V standards. The lack of stringent M&V rules can result in compensating demand resources when no verifiable usage reduction took place, or when a usage reduction occurred for reasons other than in response to the market price. Such occurrences can undermine the credibility and ultimately the viability of demand response programs.[93]

JCA acknowledges that development of M&V requirements may be difficult, but doing so is critical and necessary in order to ensure DR participates responsibly and brings benefits to the system.

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[92] Illinois Citizens Utility Board Comments, p. 16.

[93] JCA Comments, p. 12.

4. Due to Expected Impacts to Consumers from the Proposal, Cost Allocation Issues Must Be Addressed

Another concern that garnered an extensive amount of discussion is that the overcompensation that results if there is no retail or purchase offset creates a problem for cost allocation, as the ISO/RTO will not be revenue neutral if it must pay for a product that is not offset by any purchase or the exercise of an option on the system at any point. Additionally, cost issues generally impact how much DR is beneficial to the system and to consumers. The National Action Plan on Demand Response points out,

> Determining the cost-effective mix of demand response programs is a central challenge to any demand response provider, regulator, or policymaker. Projections of long-term benefit streams (such as avoided resource costs), identification of relevant costs, and the accurate characterization of these costs are examples of the types of calculations that must be made in assessing a program's cost-effectiveness. The creation of cost-effectiveness tools is essential to determining the most efficient mix of demand response programs for a given service territory or region.[94]

Regarding the NOPR proposal in particular, OMS notes that the problem of cost allocation threatens the

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[94] The National Action Plan on Demand Response, p. 74.

very promotion of consumer level demand response that the Commission seeks to support with this proceeding. OMS states,

> LSEs and State Commissions are more likely to support the provision of demand response by ARCs in the RTO markets if non-participating customers do not have to bear additional costs as a result.
>
> The OMS does not support the uplift of the costs of payments to ARCs. This would penalize states and LSEs which have implemented and or are planning to implement improved and innovative retail rate structures using smart metering technology.[95]

The Midwest TDUs also note this concern:

> Although electricity is not tangible in the same way as an airline ticket, the analogy applies: the demand responder cannot both be paid LMP *and* receive the retail tariff savings realized by not consuming energy. Real, metered load cannot be served with a "negawatt." There are important compensation and cost allocation considerations that arise as a consequence of this fact. Commission efforts to integrate demand response into organized market structures must allow each RTO to recognize and account for this, or will unintention-

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[95] OMS Comments, pp. 6-7.

ally undermine the very goals they are intended to advance.[96]

The TDUs explain that the extra payments made to DR providers associated with treating DR as energy requires a cost allocation methodology that recovers those costs. According to Midwest TDU, these methodologies should be developed by the ISOs/RTOs. "These decisions reflect the specific interplay between demand response resources and the retail and wholesale market structures within each region with which demand response regimes must work. Those market structures vary significantly between RTO regions."[97]

The ISO-NE explains, "With respect to cost allocation, the NOPR and proposed rule do not address how the costs resulting from payments to demand response providers ought to be allocated among market participants. Analysis conducted by ISO-NE found that some cost allocation schemes raise the overall costs charged to end-use consumers more than other schemes."[98] This concern stems from the issue that the RTOs, if paying DR full LMP in all hours, will not be revenue neutral and must assign costs to market participants in order to cover those additional costs. This concern could be resolved if LMP payments are made only when the payments result in net benefits or if there is a purchase required to offset the sale of the

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[96] Midwest TDUs Comments, p. 7.

[97] Midwest TDUs Comments, p. 10.

[98] ISO-NE Comments, p. 4.

MW (a version of this is the ISO-NE "buy the baseline" proposal). Without these assurances that DR will not cost the system additional money, then how cost allocation is handled must be addressed in the NOPR as it is the compensation proposal creating the additional costs to consumers.

D. Legal Issues

1. The Commission Lacks the Authority to Require "Just and Reasonable" Compensation for the Provision of Non-Jurisdictional DR Services

a. Even Supporters of the NOPR Concede That Providing DR Does Not Involve a FERC-jurisdictional "Sale for Resale"

Various supporters of the DR subsidies proposed in the NOPR concede, as they must, that providing DR does not involve a FERC-jurisdictional "sale for resale."[99] The Commission's regulations have explicitly defined DR as a reduction in consumption of electric energy by end-users,[100] or in other words, as a retail

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[99] *See, e.g.*, Comments Of EnerNOC In Response To Notice Of Proposed Rulemaking, pp. 7-9, Docket No. RM10-17-000 (filed May 13, 2010), DR Supporters Comments, pp. 17-18.

[100] In Section 35.28(b)(5) of its regulations, the Commission has broadly defined DR as:

> [A] reduction in the consumption of electric energy by customers from their expected consumption in response to an increase in the price of electric energy or to incentive payments designed to induce lower consumption of electric energy.

purchase that will not be or was not made. The Commission re-affirmed this finding recently in *EnergyConnect, Inc.*,[101] where it held that an entity that provides only DR services, without making sales of electric energy for resale, is not a "public utility" within the meaning of the FPA.[102] EPSA therefore agrees with these commenters that a necessary, and unavoidable, consequence of the Commission's definition and holding in *EnergyConnect* is that the Commission cannot exercise jurisdiction over DR as a jurisdictional "sale for resale."

b. The Commission Cannot Set Rates for Non-Jurisdictional Services, Even if Such Rates May "Affect" Jurisdictional Rates

While conceding that providing DR does not itself represent a FERC-jurisdictional wholesale sale, various advocates for the subsidies proposed in the NOPR

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18 C.F.R. § 35.28(b)(5) (2009).

[101] 130 FERC ¶ 61,031 (2010) ("*EnergyConnect*").

[102] In *EnergyConnect*, the Commission explained that:

> [W]here an entity is only engaged in the provision of demand response services, and makes no sales of electric energy for resale, that entity would not own or operate facilities that are subject to the Commission's jurisdiction and would not be a public utility that is required to have a rate on file with the Commission.

Id. at p. 30.

argue that the Commission can nonetheless regulate compensation for this service as a practice that affects or relates to rates for wholesale sales. As explained in the EPSA Initial Comments, however, the Commission's proposal to regulate DR compensation represents an impermissible "attempt[] to do indirectly what it could not do directly."[103] The Commission's ratemaking and refund jurisdiction under Sections 205 and 206 of the FPA[104] are expressly limited to rates charged by FPA-defined "public utilities" for jurisdictional services.[105] To the extent that the Commission determines that inadequate DR compensation in organized energy markets may have caused Commission-jurisdictional rates to become unjust and unreasonable, its remedy, if any, may "operate only against the rate of jurisdictional sales."[106]

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[103] *Altamont Gas Transmission Co. v. FERC*, 92 F.3d 1239, 1248 (D.C. Cir. 1996) ("*Altamont*").

[104] 16 U.S.C. §§ 824d, 824e (2006).

[105] *See Bonneville Power Administration v. FERC*, 422 F.3d 908, 918 (9th Cir. 2005) ("BPA"). As the *BPA* decision makes clear, the fact that DR compensation may be provided pursuant to FERC-approved tariffs does not alter the jurisdictional analysis. Indeed, notwithstanding the fact that the transactions at issue were indisputably wholesale sales in interstate commerce, that decision finds that the Commission lacked jurisdiction because those sales were made by "non-public utilities." *Id.* at 911. The court was not persuaded by the Commission's claims that the sales at issue were made in markets administered by public utilities with "FERC-approved tariffs." *Id.* at 918.

[106] *FPC v. Conway Corp.*, 426 U.S. 271, 279 (1976) ("*Conway*").

The fact that some DR providers may be public utilities based on their other business activities does not compel a different result. Where a regulated entity provides both Commission-jurisdictional and non-jurisdictional services, the Commission may only exercise its ratemaking authority with respect to the jurisdictional services.[107] Thus, the Commission may not regulate the rates for non-jurisdictional DR services, whether the provider is a non-public utility or a public utility that, like the one in *EnergyConnect*, also makes jurisdictional sales.

Contrary to the claims of certain commenters,[108] the D.C. Circuit's holding in *Connecticut Department of Public Utility Control v. FERC*[109] does not support the assertion of jurisdiction over DR compensation. There, the court held that, because the Commission had direct ratemaking jurisdiction over the capacity prices in question, it could also indirectly regulate capacity prices through setting the inputs that would affect the prices paid for capacity,[110] or in other words, that the power to set rates directly "include[s] the

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[107] *See, e.g., Colorado Interstate Gas Co. v. FPC*, 324 U.S. 581, 588 (1945).

[108] *See, e.g.*, DR Supporters Comments, Attach. A at 13 n.41.

[109] 569 F.3d 477 (D.C. Cir. 2009) ("*Connecticut DPUC*").

[110] In *Connecticut DPUC*, the Court of Appeals for the D.C. Circuit upheld a Commission order accepting ISO New England Inc.'s Installed Capacity Requirement" (the "ICR"), which the court described as "a key input into the market-based mechanism" for determining ISO-NE capacity prices. *Id.* at 478-79.

power to do so indirectly."[111] Unlike the capacity prices at issue in *Connecticut DPUC*, however, the Commission lacks the authority to directly set rates for DR services. Thus, given that *Connecticut DPUC*'s antecedent condition is not satisfied, then its conclusion that the Commission may regulate such non-jurisdictional rates as a practice affecting jurisdictional rates does not follow.

Where the Commission is foreclosed from directly regulating non-jurisdictional rates, it may not circumvent the limits on its statutory authority simply by claiming the authority to do so based on the fact that such non-jurisdictional rates may "affect" jurisdictional rates. EPSA notes that, in this regard, DR is no different than any other non-jurisdictional input that may "affect" the price of jurisdictional rates (*e.g.*, steel, cement, coal, etc.). Even if an increase in DR compensation in energy markets would lower jurisdictional rates, this effect does not, in and of itself, empower the Commission to set rates for DR, any more than the Commission would be justified to reaching out to regulate rates for cement, steel, coal, or other goods or services affecting the price of electricity. To argue that it does would read out of the FPA the express restrictions on the Commission's ratemaking authority and would thus violate one of the cardinal rules of statutory construction, namely, that a statute must be read to "avoid an interpretation that renders

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[111] *Id.* at 482.

any part of it superfluous and does not give effect to all of the words used by Congress."[112]

Finally, EPSA notes that the NOPR does not appear to make any distinctions between the different types of DR service providers,[113] nor does it explain whether there are any differences in the manner in which the different types of DR service providers affect jurisdictional rates and the significance of these differences for the Commission's regulation. In particular, the Commission has not explained whether and to what extent these different types of DR service providers will be subject to other Commission rules and requirements, *e.g.*, whether either type of DR service provider would be required to obtain market-based rate authority or whether these service providers would be subject to ISO/RTO market power mitigation measures.

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[112] *Beisler v. Commissioner*, 814 F.2d 1304, 1307 (9th Cir.1987).

[113] EPSA notes that there are at least two types of DR providers. First, there are large industrial customers that purchase directly from the ISOs/RTOs and that would provide DR services by agreeing to reduce their own consumption. These DR service providers likely would not be considered "public utilities" within the meaning of the FPA. Second, there are third-party DR service providers (*e.g.*, load-serving entities or retail aggregators) that will function as an intermediary between the ISOs/RTOs and multiple end-users (whether residential, industrial, or commercial) that have agreed to reduce their consumption under specified circumstances. An entity in this second class of DR service providers may or may not be public utilities, depending on whether it makes jurisdictional sales for resale.

c. The NOPR Fails to Establish that Jurisdictional Rates are Unjust and Unreasonable or That, If They Were, Increased DR Compensation Is the Appropriate Remedy

Even assuming *arguendo* that the Commission could assert jurisdiction over DR compensation as a practice affecting FERC-jurisdictional wholesale rates, it would still be required to focus on the effect of DR compensation on wholesale rates and not the adequacy of that compensation as such. More importantly, the Commission would need to explain why and how existing rates are unjust and unreasonable and why and how the amount of DR compensation proposed will cause rates to be just and reasonable. Blanket assertions that increased DR compensation will lower jurisdictional rates and mitigate market power, even if true, utterly fail to answer these questions, much less to provide the substantial evidence and reasoned decision-making necessary to survive judicial review. Moreover, if the basis for the Commission's assertion of jurisdiction over DR compensation is its effect on jurisdictional rates, then the Commission may set such compensation only to the extent that DR compensation actually affects or relates to the justness and reasonableness of jurisdictional rates.[114]

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[114] *See, e.g., Transmission Agency of Northern California v. FERC*, 495 F.3d 663 (D.C. Cir. 2007) ("*TANC*"). In *TANC*, the court affirmed the Commission's decision to review the justness and reasonableness of the transmission revenue requirement

The Commission may not review such rates to determine whether the non-jurisdictional seller is receiving adequate or excessive compensation.[115]

EPSA notes that numerous commenters advocating the subsidies to DR proposed in the NOPR parrot the NOPR's conclusory claim that increased DR compensation will lower jurisdictional rates by providing additional mitigation of generator market power.[116] The underlying—and unsupported—assumptions appear to be that generators currently have the ability to exercise market power and that existing ISO/RTO mitigation is inadequate to address such market power. This argument ignores the fact that the Commission accepted the existing ISO/RTO market power mitigation measures because it found them to be just and reasonable on their own,[117] without reference to the

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("TRR") of the City of Vernon, California ("Vernon"), a governmental entity excluded from the definition of public utility, because it found that the Commission had "sufficiently demonstrated that it is impossible to ensure that [the jurisdictional] rates are just and reasonable without reviewing Vernon's TRR under the same standard." *Id.* at 672.

[115] *See id.* at 674 (holding that the Commission could not fix Vernon's TRR at a just and reasonable level by requiring refunds).

[116] *See, e.g.*, Joint Comments Of Public Interest Organizations On Notice Of Proposed Rulemaking, p. 4, Docket No. RM10-17-000 (filed May 13, 2010); Viridity Reply Comments, p. 27.

[117] *See, e.g., Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697-A, FERC Stats. & Regs. ¶ 31,268 at P. 111 (2008)

level of DR compensation or participation. Moreover, the ISOs/RTOs and their respective market monitors have consistently found that ISO/RTO energy markets are competitive and that suppliers are not capable of exercising market power.[118] Finally, given that existing mitigation has been found to be just and reasonable, the Commission's proposal may result in over-mitigation, which, as the Commission has recognized, may be just as harmful to competition as under-mitigation and can reduce regulated sellers' rates to unjust and unreasonable levels.[119]

Conversely, the NOPR completely ignores the risk that its proposal may facilitate the exercise of buyer market power[120] and fails to propose, or even suggest,

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(adopting a "rebuttable presumption that the existing [ISO/RTO] mitigation is sufficient to address any market power concerns.").

[118] *See generally* EPSA Initial Comments, pp. 15-19. This argument that increased DR compensation is necessary to lower prices is particularly troubling in light of the current market conditions in which electricity prices fell by half from 2008 to 2009 and are currently at the lowest levels since the inception of organized markets. *See id.*, p. 15.

[119] *See, e.g., Wisconsin Public Power, Inc. v. FERC*, 493 F.3d 239 (D.C. Cir. 2007) (affirming Commission decision not to impose additional mitigation where the additional mitigation may have reduced prices to a level below that necessary for generators to recover their fixed costs).

[120] For example, the Commission does not appear to have considered the possibility that DR service providers' ability to suppress demand and lower prices may itself be an exercise of market power.

measures to monitor or mitigate any increased buyer market power resulting from the proposal. EPSA submits that the risk of buyer market power is in fact heightened with respect to DR in light of the fact that many DR service providers will not be public utilities subject to the full scope of Commission requirements and sanctions for unlawful conduct.

In addition, these commenters ignore the fact that the NOPR makes no attempt to quantify the amount by which jurisdictional rates are excessive, the effect of increased DR compensation on lowering jurisdictional rates, or the net effect of the proposal on jurisdictional sellers' compensation. In particular, the NOPR fails to consider whether the Commission's proposal would lower jurisdictional rates to such a degree that it would violate jurisdictional sellers' statutory and constitutional rights to just and reasonable compensation,[121] and if so, whether the Commission should

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[121] *See generally Smyth v. Ames*, 169 U.S. 466, 546 (1898); *Bluefield Waterworks & Imp. Co. v. Public Service Commission of W. Va.*, 262 U.S. 679, 690 (1923); *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 602 (1944) ("*Hope*"). In its reply comments, Viridity Energy, Inc. ("Viridity") suggests that concerns about price suppression depriving public utilities of their statutory and constitutional rights to just and reasonable compensation are "meritless," because the Commission's market-based rate approach allows "fundamental competitive market conditions [to] determine the return earned by market participants—not administratively set rates." Viridity Reply Comments, p. 23. Viridity misses the point. The Commission's shift to a market-oriented regulatory regime did not eliminate the statutory and constitutional right of

loosen or eliminate other mitigation measures to ensure that the resulting rates are compensatory. By solely focusing on the potential for DR to lower prices, without regard to whether these rates are confiscatory or whether they strike the appropriate balance between consumers' and investors' interests, the NOPR's proposal, if adopted, would represent an abdication of the Commission's obligations under the FPA and the U.S. Constitution to ensure that the rates that jurisdictional public utilities receive for jurisdictional sales are just and reasonable.

2. The Commission's Proposal Violates the Rulemaking Requirements of the FPA and the APA

a. Implementation of the NOPR's Proposal Would Require the Commission to Find that Existing ISO/RTO DR Compensation Provisions Are Unjust and Unreasonable

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suppliers to just and reasonable compensation. And, as the Commission and the courts have recognized, over-mitigation, like that which would result from subsidized DR layered on top of existing mitigation in organized markets, can result in rates that are not just and reasonable. *See, e.g., Wisconsin Pub. Power, Inc. v. FERC*, 493 F.3d 239 (D.C. Cir. 2007). *See also generally* EPSA Initial Comments, pp. 38-46.

The DR Supporters make the unsupported and erroneous assertion that the Commission may exercise its authority to adopt the regulations proposed in this NOPR without first finding that existing DR compensation approaches are unjust and unreasonable.[122] This is simply false.

The Commission proposes to require all ISOs/RTOs (with the apparent exception of the Southwest Power Pool, Inc.) to modify their existing, Commission-approved tariff provisions governing DR compensation. Under the FPA, the Commission's only power to require modifications to filed rate schedules and tariffs arises under Section 206 of the FPA,[123] which requires that the Commission find the existing rates to be unjust and unreasonable, or unduly discriminatory or preferential *and* the proposed modifications to be just and reasonable and not unduly discriminatory or preferential. The DR Supporters offer no precedent for their sweeping claim that the Commission is relieved of the requirements of the FPA when it is exercising a "legislative" function.[124] The

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[122] DR Supporters Comments, p. 29.

[123] *See, e.g., Exxon Mobil Corp. v. FERC*, 571 F.3d 1208, 1215 (D.C. Cir. 2009).

[124] *Id.* Instead, to support this proposition the DR Supporters cite *Midwest Indep. Sys. Op., Inc. v. FERC*, 388 F.3d 903 (D.C. Cir. 2004), which affirmed the Commission's decision **not** to initiate a rulemaking. The cited case thus has no bearing on the question at issue, namely, whether a Commission may direct transmission providers, on a generic basis, to change existing tariff provisions with-

Commission, like any other federal regulatory agency, "is a creature of statute, and . . has only those authorities conferred upon it by Congress."[125] Although courts grant agencies a certain degree of deference in reviewing their policy decisions and interpretations of the law, agencies receive no deference when their action is not authorized by their enabling statute.[126] Where the Commission has issued legislative-type rules that modify rates on a generic basis, as it proposes to do in the NOPR, it has made the generic findings required under Section 206 of the FPA, through a rulemaking proceeding, that a given rate or practice is unlawful and that its proposed replacement is just and reasonable, and not unduly dis-

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out finding those provisions to be unlawful under Section 206 of the FPA.

[125] *Nat'l Ass'n of Regulatory Util. Comm'n v. FERC*, 475 F.3d 1277, 1286 (D.C. Cir. 2007) (internal citations omitted).

[126] Commission interpretations of the FPA are reviewed by applying the two-step analysis of *Chevron U.S.A. Inc. v. Natural Resources Defense Council, Inc.*, 467 U.S. 837, 104 (1984) ("*Chevron*"). Under this analysis, the court first determines "whether Congress has directly spoken to the precise question at issue." *Id.* at 842. "If the intent of Congress is clear, that is the end of the matter; for the court, as well as the agency, must give effect to the unambiguously expressed intent of Congress." *Id.* at 842-43. Under the *Chevron* doctrine, an "agency's interpretation of [a] statute is not entitled to deference absent a ***delegation of authority*** from Congress to regulate in the areas at issue." *Am. Library Ass'n v. FCC*, 406 F.3d 689, 699 (D.C. Cir 2005) (emphasis in original) (citation omitted)).

criminatory and preferential.[127] Thus, Commission and judicial precedent are clear that the Commission must first make such findings supported by record evidence under FPA Section 206 ***before*** it may require ISOs/ RTOs to change tariff provisions it has previously found to be lawful.

b. The NOPR Does Not Provide Interested Parties a Meaningful Opportunity for Notice and Comment

EPSA notes that the DR Supporters claim that the Commission need not "find that the various existing approaches to compensation for demand response are unjust and unreasonable in order to ***initiate*** this rulemaking proceeding."[128] While it is true enough that the Commission was free to initiate this rulemaking proceeding without such a finding, that does not alter

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[127] *Transmission Access Policy Study Group v. FERC*, 225 F.3d 667, 686-690 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002) (upholding the Commission's authority to issue Order No. 888, which required transmission providers' to provide transmission service under the Commission's *pro forma* open access transmission tariff ("OATT"), pursuant to the Commission's generic findings under Sections 205 and 206 of the FPA that certain industry practices were unduly discriminatory and that the proposed replacement, the *pro forma* OATT, was just and reasonable, and not unduly discriminatory or preferential). *See also Associated Gas Distributors v. FERC*, 824 F.2d 981, 998 (D.C. Cir. 1987) (upholding open access requirements for interstate pipelines based on generic findings of undue discrimination pursuant to Section 5 of the Natural Gas Act, 15 U.S.C. § 717d (2006)).

[128] *Id.* (emphasis added).

the fact that by doing so the NOPR fails to give interested parties the notice and opportunity for comment required by the Administrative Procedures Act ("APA").[129] To comply with this obligation, the Commission must identify the reasoning and record evidence upon which it has relied in reaching its decision, so that interested parties have an opportunity to rebut the evidence proffered by the Commission,[130] and it must do so before issuing its final rule,[131] *e.g.*, in the NOPR.

The Commission has not pointed to any evidence whatsoever demonstrating that current DR compensation levels render jurisdictional rates unjust and unreasonable or that increasing DR compensation as proposed is necessary for such rates to become just and reasonable.[132] Moreover, this inadequacy is un-

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[129] 5 U.S.C. § 553 (2006).

[130] *See, e.g., WJG Tel. Co., Inc. v. FCC*, 675 F.2d 386, 389 (D.C.Cir.1982); *Chamber of Commerce v. SEC*, 443 F.3d 890, 899 (D.C.Cir.2006).

[131] *American Radio Relay League, Inc. v. FCC*, 524 F.3d 227, 237 (D.C. Cir. 2008) (emphasis added). *See also Connecticut Light and Power Co. v. NRC*, 673 F.2d 525, 530 (D.C. Cir. 1982), *cert. denied* 459 U.S. 835 (1982).

[132] The EPSA Initial Comments explain that the only evidence cited by the Commission in support of its proposal—a report by the market monitor for PJM Interconnection, L.L.C.—stands for precisely the opposite proposition, namely, that changes in DR compensation were not responsible for reduced DR participation. *See* EPSA Initial Comments, pp. 27-28. Similarly, Commission Moeller concluded, "the NOPR lacks a thorough discussion of the

settling in light of the incorporation of the record from the PJM proceeding, which, as Commissioner Moeller correctly notes, "shows wide disagreement in the industry regarding the issue of demand response compensation."[183] Even though the record in that proceeding shows divergent and even contradictory evidence regarding the appropriate level of DR compensation, the Commission made no effort in the NOPR to identify the evidence that supports its proposal or to refute the overwhelming evidence that does not.

III. CONCLUSION

WHEREFORE, for the foregoing reasons, EPSA respectfully asks that the Commission consider these reply comments in formulating any final rule in this proceeding. The record that has been established in response to the NOPR is helpful in achieving the laudable goal of DR's participation in the wholesale markets, and should be instructive for finding practical solutions that will not create negative unintended consequences. The limited regulatory language in the NOPR opened the door for commenters to raise the additional steps and considerations that should be part of this proceeding. With all due respect to parties filing in support of the NOPR as issued, they do the cause of DR a disservice by not proposing regulatory

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evidence that they relied upon to substantiate their concerns." NOPR, Commissioner Moeller Statement Concurring in Part and Dissenting in Part, p. 2 ("Commissioner Moeller Statement").

[183] Commissioner Moeller Statement, p. 3.

language or solutions to the clear and agreed upon concerns that must accompany a compensation mechanism. EPSA looks forward to continuing this dialogue and working with all interested parties to craft an approach that is truly beneficial to the wholesale electricity markets and to consumers.

Respectfully submitted,

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Dated: June 30, 2010

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UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. RM10-17-000

DEMAND RESPONSE COMPENSATION IN ORGANIZED
WHOLESALE ENERGY MARKETS

Aug. 30, 2010

REPLY COMMENTS OF THE DEMAND RESPONSE SUPPORTERS

On March 18, 2010, the Federal Energy Regulatory Commission ("Commission") issued a Notice of Proposed Rulemaking ("NOPR") to adopt an approach for compensating demand response resources[1] in order to improve the competitiveness of organized wholesale energy markets and ensure just and reasonable wholesale rates.[2] On and about May 13, 2010, numerous parties, including the Coalition of Midwest Transmission Customers; the PJM Industrial Customer Coalition; Comverge, Inc.; EnergyConnect, Inc.; EnerNOC, Inc.; Viridity Energy, Inc.; and Wal-Mart Stores, Inc. (collectively, "Demand Response Support-

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[1] These Reply Comments will sometimes refer to "Demand Response" or "Demand Response Resources" as "DR."

[2] *Demand Response Compensation in Organized Wholesale Energy Markets*, 130 FERC ¶ 61,213 (2010).

ers") filed Comments addressing the Commission's initiative to determine the critical issue of demand response compensation on a generic basis across organized markets, in the context of a rulemaking. Demand Response Supporters file these Reply Comments[3] to respond to some parties' assertions that payment of full Locational Marginal Price ("LMP") for demand response resources is inappropriate and also to provide additional evidence demonstrating why full LMP payment for demand response resources is appropriate and necessary for regulated wholesale electricity markets.[4]

Demand Response Supporters look forward to the Technical Conference on the issues of "net benefits" determinations and appropriate settlement of demand response payments. Demand Response Supporters will address these issues in written Comments following the Technical Conference.

I. INTRODUCTION AND EXECUTIVE SUMMARY

Even a cursory review of the voluminous comments filed in this proceeding leads to the conclusion that

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[3] Demand Response Supporters acknowledge that the Commission did not expressly allow or disallow Reply Comments in this proceeding. To the extent necessary, Demand Response Supporters seek leave to reply and have these Reply Comments considered by the Commission.

[4] Demand Response Supporters' non-response to any Comments should not necessarily be interpreted as agreement with those Comments.

most commenters agree that demand response provides benefits to organized wholesale energy markets.[5] Given this general agreement, the only policy question faced by the Commission is this:

> What approach will most effectively incorporate demand response into the wholesale markets, over which the Commission has jurisdiction, to deliver benefits from those markets to customers?

The Commission's proposed Rule gets it right.[6]

The ultimate policy decision should not be driven solely by various economic theories, nor should it be hijacked by arguments made by parties not interested in lowering or flattening overall demand,[7] but rather

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[5] *See, e.g.*, Comments of National Energy Marketers Association (May 13, 2010); Comments of Integrys Energy Services, Inc. at 3 (May 13, 2010); Comments of the Detroit Edison Company at 2 (May 13, 2010); Comments of the Independent Market Monitor for PJM (May 14, 2010).

[6] The Commission issued a Supplemental Notice of Proposed Rulemaking and Notice of Technical Conference, 132 FERC ¶ 61,094, on August 2, 2010 ("Supplemental NOPR"). Demand Response Supporters do not herein discuss the topics covered by the Supplemental NOPR.

[7] *See* Reply Affidavit of Dr. Alfred E. Kahn, Attachment A to these Reply Comments ("Kahn Reply Affidavit"), which states, in part: "That electricity generators have opposed this plan should not be surprising: their primary business is to sell power not to encourage its conservation, and I have myself publicly cited evidence that they reap the preponderance of their profits on those occasions when demand is at its peak." Kahn Reply Affidavit at 12, citing "The Adequacy of Prospective Returns on Generation In-

should look to relative customer costs and benefits of implementing full LMP as the correct compensation for demand response participation in energy markets. The comparison of relative customer costs and benefits squares fully with the Commission's charge under the Federal Power Act, which, as both the Supreme Court and the U.S. Court of Appeals for the District of Columbia Circuit have recognized, requires the Commission to stand as the watchdog providing "a complete, permanent and effective bond of protection from excessive rates and charges"[8] and to "guard" the consumer from exploitation, consistent with Congress' objectives in implementing the Federal Power Act.[9]

Some parties oppose the NOPR's proposed approach, offering various theoretical arguments and suppositions, while downplaying or even purposefully ignoring the real-world benefits that would result from full LMP compensation for DR.[10] Many of these

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vestments under Price Control Mechanisms," *The Electricity Journal*, 15:2, March 2002, pp. 7-46.

[8] *Jersey Central Power & Light v. FERC*, 810 F.2d 1168, 1207 (D.C. Cir. 1987)(citing *Atlantic Refining Co. v. Public Service Commission*, 360 U.S. 378, 388, 79 S.Ct. 1246, 1253, 3 L. Ed. 2d 1312 (1959)).

[9] *See Nat'l Ass'n for the Advancement of Colored People v. Fed. Power Comm'n*, 520 F.2d 432, 438 (D.C. Cir. 1975).

[10] *See, e.g.*, Comments of the Electric Power Supply Association at 4 ("The NOPR as issued will not achieve its stated objectives due to a number of significant legal, economic, policy and operational flaws with the DR compensation proposal."); Comments of the PJM Power Providers Group at 11, 50 (stating that full LMP compensa-

comments come from suppliers. The irony, of course, is that suddenly suppliers are pretending to know better than customers what will benefit customers. These Reply Comments, and the attached Reply Affidavit of Dr. Alfred E. Kahn, provide the customer perspective and rebut the theoretical offerings that try to move the Commission away from its NOPR proposals.[11]

Other commenters attempt to degrade the value of demand response by insisting that this Commission should reduce demand response compensation by the amount of a retail generation rate. These assertions must fail either due to flawed economic theory or due to a misapplied attempt to render retail rates "efficient."[12] In this proceeding, the Commission should focus exclusively on the correct approach to wholesale market compensation for demand response resources and not entertain any efforts to alter that course.

These Reply Comments address the following points:

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tion is "inappropriate" without a retail offset); Comments of the Midwest TDUs at 5 (arguing that full LMP "overcompensates" demand response, which is not a comparable resource to generation); Comments of Monitoring Analytics, LLC, Independent Market Monitor for PJM at 5-6 (asserting that the true "fix" for the market is fully transparent prices to consumers).

[11] *See generally* Kahn Reply Affidavit.

[12] As Dr. Kahn states in his Reply Affidavit, at 23-25, the Commission should not and need not concern itself with the efficiency of retail markets.

- The Federal Power Act gives the Commission, and the Commission has rightfully claimed, the broad authority to correct market flaws, including compensation for demand response;
- Full LMP compensation for demand response is in the public interest and facilitates an optimized wholesale energy market;
- The Final Rule correctly applies to "market pricing," and allows for differences among RTO and non-RTO regions;
- Wholesale rate issues, including compensation for demand response, are "practices affecting wholesale rates" and thus fall squarely within the Commission's jurisdiction;
- The NOPR appropriately recognizes that demand response faces many barriers and discrimination to participation in wholesale energy markets, which can only be remedied with comparability among compensation mechanisms;
- The Final Rule should apply to all RTO regions for all hours; and
- This Rulemaking does not implicate reliability issues; claims to the contrary should be rejected as irrelevant and unfounded.

II. REPLY COMMENTS

A. The Commission Does Not Need To Determine That Existing Rates Are Just And Reasonable In Order to Correct The Current Compensation Disparity Between Generation and Demand Resources.

EPSA and others assert that the NOPR fails to provide any detailed substantive analysis supporting what EPSA referred to as the NOPR's "summary" legal conclusions that (a) the current FERC-approved wholesale prices are no longer just and reasonable, (b) the new pricing proposal is just and reasonable, and (c) the concept that a just and reasonable price means a "lower" price.[13] The PJM Power Providers ("P3") voiced similar concerns, asserting that, under Section 206 of the Federal Power Act,[14] the Commission can only initiate a change in a public utility's rates or other service terms if it first demonstrates that existing service terms or rates are unjust, unreasonable, unduly discriminatory or preferential.[15] Furthermore, P3 also contends that, once the Commission meets that burden, it also must demonstrate that the terms and conditions it proposes to substitute for those in effect are just and reasonable.[16] Several other parties

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[13] *Id.* Comments of PJM Power Providers ("P 3 Comments") at 16.

[14] 16 U.S.C. § 824e.

[15] P 3 Comments at 16.

[16] *Id.*

voiced similar concerns.[17] These broad arguments are rooted in a mistaken belief that the Commission's authority to set proper compensation for demand response derives exclusively from FPA Section 206.

These comments are simply incorrect. The Commission does not need to find that existing rates are not just and reasonable in order to implement a market enhancement.[18] The Federal Power Act—and relevant case law—offer the Commission broad rulemaking authority, specifically the "power to perform *any and all acts, and to prescribe, issue, make, amend, and rescind such orders, rules, and regulations* as it may find necessary or appropriate to carry out the provisions of this chapter [i.e., the FPA]."[19]

In addition, it must be noted that there is a difference between a proposed market enhancement that the Commission has the authority to direct based on the "public interest," on one hand, and a "change in a public utility's rates or terms of service," on the other. Market enhancements may fall within the Commission's rulemaking authority and, accordingly, the Com-

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[17] *See, e.g.*, Monitoring Analytics Comments at 8 n.6 (quoting Commissioner Moeller's partial concurrence and dissent in the NOPR).

[18] *See* Comments of The Coalition of Midwest Transmission Customers; Comverge, Inc.; EnergyConnect, Inc.; EnerNOC, Inc.; the PJM Industrial Customer Coalition; Viridity Energy, Inc; and Wal-Mart Stores, Inc. at 29.

[19] *Midwest Indep. Trans. Sys. Operator v. FERC*, 388 F.3d 903, 908 (D.C. Cir. 2004) (emphasis added)(citing 16 U.S.C. § 825h).

mission may propose necessary modifications to its regulations *sua sponte*, provided the modifications are subject to notice and comment procedures and are consistent with the public interest.[20] Based on this broad rulemaking authority, the Commission may adopt regulations that address appropriate compensation for demand response without making a finding that existing rates are unjust and unreasonable.

Even though the Commission need not take the steps prescribed by Section 206 of the Federal Power Act, if the Commission determines that it must make a Section 206 finding, it could do so given the information and evidence in the record.

First, undue discrimination does exist between the compensation available generation and the compensation available to demand response resources in organized wholesale markets, and this situation does require a remedy.[21] Simply, generation and demand response resources benefit the grid comparably but do not receive comparable compensation.

Second, this discrimination has already resulted—and continues to result—in less-than optimal opportunities for demand response resource participation in

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[20] *See, e.g., Texaco Inc. and Texaco Gas Marketing Inc. v. FERC*, 148 F.3d 1091, 1097 (D.C. Cir. 1998) (discussing the Commission's authority to promulgate rules, the Court stated that, "FERC's rulemaking authority requires only that it point to a generic public interest in favor of a proposed rule.").

[21] *See, e.g.*, Orders 719 and 719-A.

the wholesale market and has prevented or minimized the many recognized benefits that demand response could provide to wholesale markets and to customers. The Commission appropriately recognized this market defect in issuing the NOPR, and remedying this undue discrimination between resources is well within the Commission's broad FPA authority.

Third, the Commission would be further justified to make a Section 206 finding and adopt the proposed rule because rates to customers are not just and reasonable if insufficient demand response currently exists in today's markets. Put another way, because customers are being denied the benefits that demand response provides in the form of lower and smoother LMPs,[22] customers are paying unjust and unreasonable prices for electricity. The evidence cited in this proceeding, as well as in the PJM Complaint[23] proceeding regarding demand response compensation, gives the Commission ample, defensible grounds upon which to make a finding that the Commission must adopt the corrective measures proposed in the NOPR.

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[22] Order 719-A at P. 47; *Quantifying Demand Response Benefits in PJM*, the Brattle Group, prepared for PJM Interconnection, LLC and the Mid-Atlantic Distributed Resources Initiative ("MADRI") (Jan. 29, 2007); *see also* Kahn Reply Affidavit at 15-17, finding benefits for *all consumers*, including lowered overall demand, reductions in costs to residual customers, and a general support for "the most severe deficiency in most such markets in the US, the lack of an adequately, price-responsive demand side."

[23] *PJM Interconnection, Inc.*, Docket No. EL09-68.

Based on the above, the Commission is well within its statutory rights to adopt the NOPR provisions; arguments to the contrary must be rejected.

B. Compensating Demand Resources At Full LMP Is In The Public Interest And Optimizes Wholesale Energy Markets.

Several parties continue to claim that there is no showing or evidence in the NOPR that additional steps, such as paying demand response full LMP in all hours in all organized markets, is necessary to ensure either the competitiveness of the markets or that wholesale rates continue to be just and reasonable.[24] For example, EPSA concludes that the NOPR ignores market monitors' reports and other evidence that ISO/RTO wholesale electric markets, including energy markets, are and have been competitive and any market power is already sufficiently mitigated without the NOPR's proposal.[25] P3 argues that the Commission did not present any studies showing the specific "optimal" level of demand response to justify the conclusion that current levels are inadequate.[26] The PPL parties suggest that, over the long-term, paying full LMP to demand resources will "harm competitive wholesale market and decrease reliability."[27]

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[24] *See, e.g.*, EPSA Comments at 3.

[25] *Id.* at 6, 53.

[26] P3 Comments at 18-19.

[27] Comments of the PPL Parties at 9.

As a threshold matter, and while important in various ways, market monitors' reports and evaluations do not assess the overall public interest. Rather, these reports largely focus only on the competitiveness of RTO-coordinated market results. In addition, market monitors' analyses focus on whether "results" are competitive[28]—a finding that has been reached, and continues to be reached, even in the face of structurally non-competitive markets.[29] Market monitors'

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[28] *See, e.g.*, PJM State of the Market Report, Monitoring Analytics LLC at 6 (May 14, 2010) (concluding that "[th]e overall results support the conclusion that prices in PJM are set, on average, by marginal units operating at or close to their marginal costs. This is strong evidence of competitive behavior and competitive market performance."); Midwest ISO 2008 State of the Market Report (July 2009)("As the Independent Market Monitor ("IMM") for the Midwest Independent Transmission System Operator ("Midwest ISO"), Potomac Economics is responsible for evaluating the competitive performance, design, and operation of the wholesale electricity markets operated by the Midwest ISO. In this State of the Market Report, we provide our annual evaluation of the Midwest ISO's markets and our recommendations for future improvements."); New York ISO 2008 State of the Market Report (Sept. 2009), Potomac Economics, Ltd. (stating that "[t]his report assesses the efficiency and competitiveness of New York's wholesale electricity markets in 2008.").

[29] The United States Energy Information Administration reports that in 2008, net electric power generation totaled 4,119 million megawatt-hours, while all demand side management programs, plus energy efficiency measures, totaled only 87.8 million megawatt-hours (roughly 2% of the total). *See* Electric Power Annual, "Electric Power Industry: Year In Review," http://www.eia.doe.gov/cneaf/electricity/epa/epa_sum.html (Jan. 21, 2010).

findings that certain market results are consistent with competitive outcomes does not compel particular results in this Rulemaking.

In contrast, the key issue—and the issue being addressed by this NOPR—is whether markets are optimized or, put another way, working at full strength for the benefit of customers and the public interest. In contrast to P3's assertions, the less-than optimal levels of demand response are in fact widely acknowledged in State of the Market reports to the point that no party to this proceeding can reasonably conclude that markets are optimized. For example, in the 2009 State of the Market Report for PJM,[30] PJM's Market Monitor notes that many significant barriers exist to optimal participation by demand response resources in PJM's markets. In addition, the PJM Market Monitor has reported that "the Economic Load Response Program, settlement MWh and credits decreased significantly in 2008 compared to 2007, and have further decreased through March of 2009. Other indications of participation, such as total MWh reductions and credits to CSPs decreased in 2008 compared to 2007." In the Midwest ISO, its Market Monitor reported on the "substantial" potential for demand response and need for Midwest ISO to incorporate it into its market.[31] In addition, in the 2009 Annual Report for the California

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[30] 2009 State of the Market Report for PJM; Monitoring Analytics, LLC, Internal Market Monitor for PJM (Mar. 11, 2010) at 10.

[31] 2008 State of the Market Report for the Midwest ISO, Potomac Economics at 25, 50 (June 2009).

ISO ("Cal-ISO"), the Market Monitor discussed how the lack of direct demand response participation existed in the Cal-ISO and expressed a need to address it in the context of Order 719.[32] The Commission has rightly concluded that this market failure needs to be corrected, and the NOPR will accomplish its goal.

Several also argue that the correct level of compensation is not full LMP but, rather, LMP minus the generation component of the retail rate ("LMP-G"), or even less.[33] Many of these flawed arguments are premised upon a mistaken belief that the demand response resource at first acquires the energy and then "resells" it to the market.[34] However, as Demand Response Supporters have pointed out previously in this proceeding, the "resale" of energy concept has already been rejected by the Commission in *EnergyConnect, Inc.*[35] In *EnergyConnect*, the Commission stated that it was establishing a policy of treating demand response as a "service," not as a purchase and

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[32] Annual Report: Market Issues & Performance, California Independent System Operator, Department of Market Monitoring at 31 (April 2010).

[33] *See, e.g.*, P3 Comments at 3 (stating that demand resources should never be paid more than LMP-G); Comments of the Illinois Commerce Commission at 1; Comments of the Midwest TDUs at 8 (arguing for RTO-specific flexibility for determining the proper level of compensation for demand response).

[34] *See, e.g.*, Comments of Edison Electric Institute at 4.

[35] 130 FERC ¶ 61,031 (2009).

resale of electric energy.[36] The "service" is reducing "the consumption of electric energy by customers from their expected consumption in response to an increase in the price of electric energy or to incentive payments designed to induce lower consumption of electric energy."[37]

The LMP-G argument fails for other reasons. The objective of full LMP compensation is not necessarily to cause retail customers to "see" the wholesale price and, in theory, respond accordingly. Rather, the objective is to enhance opportunities for demand response given the higher cost and, in some instances, inefficiency of building or procuring additional generation and the very cost of providing demand response.[38] For example, the PJM Market Monitor has repeatedly described the demand side of PJM's Wholesale Energy Markets as "underdeveloped,"[39] and has noted that it is "widely recognized that wholesale electricity markets will work better when a significant level of potential demand-side re-

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[36] *See EnergyConnect, Inc.*, 130 FERC ¶ 61,031 at PP. 30-31 (citing 18 C.F.R. § 35.28(b)(4)(2009)).

[37] *See id.*

[38] *See* Order No. 719 at P. 13.

[39] *See* 2008 State of the Market Report for PJM, Monitoring Analytics, LLC, Internal Market Monitor for PJM (Mar. 11, 2009) at 93; 2007 State of the Market Report, Market Monitoring Unit (Mar. 11, 2008) at 10, 93; 2006 State of the Market Report, Market Monitoring Unit (Mar. 8, 2007) at 93

sponse is available in the market."[40] In addition, in its 2006 Report to Congress, the United States Department of Energy reported, based on its review of all the wholesale energy markets across the country, that the use of demand response is "not widespread"[41] despite the many recognized benefits that demand response has proven to bring to the markets. The general lack of demand response knows no regional boundaries and should be remedied across all RTOs. Furthermore, and contrary to PPL's baseless assertions, there is no evidence to suggest that increased demand response participation will *harm* the market in any way. In fact, all of the available evidence to date suggests quite the opposite.[42]

Finally, as Dr. Kahn explains, full LMP is the correct measure for adequate and comparable payment of demand response resources and does not represent a subsidy or "double compensation" or inefficiency, as some parties suggest. Dr. Kahn, in refuting such arguments, states:

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[40] 2009 State of the Market Report at 93.

[41] Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them," A Report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005, U.S. Department of Energy (Feb. 2006) at viii ("DOE Report").

[42] *See, e.g.*, DOE Report; National Action Plan on Demand Response, Federal Energy Regulatory Commission Staff (June 17, 2010); "Recognizing the Importance of Demand Response: the Second Half of the Wholesale Electric Market Equation," Energy Law Journal, Vol. 28, No. 2, Wellinghoff, Morenoff (2007).

> Does this plan involve double compensation, as Professor Hogan asserts, at the expense of power generators—of successful bidders promising to induce efficient demand curtailment and of consumers induced to practice it? Certainly not: the decrease in the revenue of the generators is (and consequent savings by consumers are) matched by the savings in their (marginal) costs of generating that power; the successful bidders for the opportunity to induce that consumer response are compensated for the costs of those efforts by the pool, whose (marginal) costs they save by assisting consumers to reduce their purchases.[43]

Full LMP payments to demand response resources "are no more subsidies than the remunerations of generators for the power they actually sell."[44]

C. The Commission Has Properly Framed The Issue In This Rulemaking As Compensation For Demand Resources In Energy Markets.

EPSA also argues that the NOPR narrowly focuses on the ISO/RTO energy markets without any acknowledgement of the growth in, and adequate compensation of, demand response resources participating in other ISO/RTO markets (i.e., capacity, emergency, and ancillary service markets).[45] Additionally, EPSA

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[43] Kahn Reply Affidavit at 10.

[44] *Id.*

[45] EPSA Comments at 6, 66.

asserts that the Commission should look at demand response resource participation across all markets in each ISO/RTO to measure its growth in the organized markets. According to EPSA, the capacity market should be the primary baseline for this evaluation given the nature of demand response products and their measurement.[46] In short, EPSA appears to be arguing that the growth in demand response and demand response compensation in capacity markets should reduce the compensation available to demand response in energy markets.

EPSA's argument, if carried to its logical conclusion and applied to generation resources, would require that the inframarginal energy revenue to each generator from participation in the day-ahead and real-time energy markets should be reduced by the level of capacity revenue received by that generator, a point likely to engender little support from supply-side interests. As the Commission is aware, under current rules, generators are paid for multiple services, such as capacity, energy, and ancillary services. In each market, generators that clear the market receive the market-clearing price. The level of participation by generation resources in a particular market or the level of compensation received by an individual generator does not dictate participation or compensation opportunities in other markets. The Commission has not foreclosed revenue opportunities in one market

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[46] *Id.*

based on revenue opportunities in another market, as EPSA suggests should be done for demand response resources. While customers would not necessarily be opposed to a broad application of EPSA's proposal to all resources, it is unduly discriminatory under current rules to single out demand response for limited revenue opportunities in the energy market as a consequence of their participation in other markets.

D. The Proposed Rule Correctly Applies To "Market Prices" And Allows For Differences Among RTOs and Non-RTO Regions.

EPSA further contends that the NOPR would inappropriately standardize only one discrete pricing element across the ISO and RTO regions, while allowing for regional differences on all other market pricing elements even though it is the totality of these interrelated pricing elements—such as how LMP is developed, whether and how periods of supply scarcity are defined, and how resource adequacy is maintained through capacity markets—that govern operational and investment decisions.[47] Contrary to EPSA's assertion, however, the NOPR is worded to apply "market prices" to demand response.[48] Although each organized market has unique market rules and designs, all organized markets have "market prices" and all organized markets have "energy markets." The NOPR does not propose that the Final Rule define

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[47] EPSA Comments at 6, 68.

[48] NOPR at 4, 6.

market prices in exactly the same fashion across all RTOs, which is an implicit recognition that differences in the definition of "market prices" exist among RTOs. Therefore, the NOPR appropriately balances the need for conceptual consistency with the recognition that market rule details vary from RTO to RTO. EPSA also criticizes the NOPR because it would require application of this standardized pricing element only in most organized markets—and does not address or require similar treatment in non-RTO regions.[49] EPSA believes that this is an inconsistent approach and that reliance on the organized markets in order to achieve a national policy goal of expanding demand response participation across the country is inappropriate.[50]

What EPSA's argument ignores is that numerous and significant differences already exist between RTO and non-RTO regions. These differences include: (1) incentives for returns-on-equity for transmission service;[51] (2) market designs;[52] (3) extent of reforms

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[49] EPSA Answer at 6, 67.

[50] *Id.*

[51] *See, e.g., Promoting Transmission Investment through Pricing Reform*, 113 FERC ¶ 61,182 ("Order 679"), *order on reh'g*, 117 FERC ¶ 61,345 (implementing EPAct Section 219, and providing for incentive-based rate treatments "for the transmission of electric energy in interstate commerce for the purpose of benefiting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion.").

[52] *See* "Notice Requesting Comments on Draft Report to Congress on Competition in the Wholesale and Retail Market for Electric Energy," FERC Staff, at 11, Docket No. AD05-17-000

required by Order 719;[53] and (4) market monitoring by independent non-governmental entities,[54] just to name a few.

(June 2006). In that Notice, Commission Staff summarizes the two basic approaches to competition in wholesale markets in the United States, which largely explains the difference between "organized markets" and other wholesale markets. In one, a market bases trades exclusively on bilateral sales directly negotiated between suppliers, rather than on a centralized trading and market clearing mechanism. This approach predominates in the Northwest and Southeast. This bilateral contract format allows for somewhat independent operation of transmission control areas and, in the view of some market participants, better accommodates traditional bilateral contracts. In the other approach, wholesale competition relies on entities that are independent of market participants to operate centralized regional transmission facilities and trading markets. The market designs in these regions provide participants with guaranteed physical access to the transmission system. Customers are responsible for the cost of that access and are exposed to congestion price risks. This more open access to transmission can increase competitive options for wholesale customers and suppliers as compared to most bilateral markets.

[53] Order 719 required several reforms to wholesale electricity markets, but limited those reforms to markets coordinated by RTOs and ISOs. In Order 719, the Commission recognized that: "[S]ignificant differences exist between regions, including differences in industry structure, mix of ownership, sources of electric generation, population densities, and weather patterns. Some regions have organized spot markets administered by an RTO or ISO, and others rely solely on bilateral contracting between wholesale sellers and buyers. We recognize and respect these differences across various regions. At the same time, wholesale competition can serve customers well in all regions. The focus of this

Given these significant recognized differences between RTO and non-RTO regions, the Commission is not compelled to ensure identical treatment in demand response compensation between RTOs and non-RTOs. The mere fact that the NOPR applies only to organized markets does not pose any legal or practical problems.

E. The Commission Has Authority Over Demand Response As a Practice Affecting Wholesale Rates.

1. While States Have Authority To Address Retail Rate Issues, Such Authority Should Not Undercut the Commission's Authority Over Demand Response.

The Commission has broad authority over practices affecting wholesale rates[55] and the Commission is uniquely positioned to address wholesale issues.[56] Some commenters argue, however, that the

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Final Rule is to further improve the operation of wholesale competitive markets in organized market regions." Order 719 at P. 9.

[54] *See* Order 719 at P. 314 (recognizing that the Commission requires RTOs and ISOs to have a market monitor, and removing market monitors from direct oversight of RTO/ISO management, and requiring enhanced information sharing by market monitors).

[55] *See* § 16 U.S.C. 824e(a); *Connecticut Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (D.C. Cir. 2009)

[56] The U.S. Court of Appeals for the District of Columbia Circuit ruled and re-emphasized the Commission's broad authority over practices affecting wholesale rates in *Connecticut Dep't of the Pub. Util. Control v. FERC*, 569 F.3d 477 (2009). There, the Court

Commission's authority extends to retail rate issues, and contend that the Commission should adopt a compensation approach for demand response that would require the Commission to delve into retail rate issues.[57] The Commission should clarify in a Final Rule the respective jurisdictional authority of this Commission and State Commissions, over demand response.

The Commission's obligation is to ensure just and reasonable wholesale rates. Establishing the right rules and compensation for demand response is an integral part of FERC's mission. State and retail regulatory authorities are uniquely positioned, both jurisdictionally and technically, to address (and they do address) retail rate issues, and correct retail rate inefficiencies to the extent such are recognized and subject to fixes.[58] Nevertheless, as Dr. Kahn aptly concludes in his Reply Affidavit, "we must give deference to a State's conception of [its] retail markets but only up to a point. And that point is where the State's actions do harm to the efforts of this Commission to maximize efficiency in the wholesale market."[59] Ar-

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expanded the Commission's jurisdiction, finding that the Commission has the authority to review the Installed Capacity Requirement ("ICR") because the ICR affects wholesale rates.

[57] EPSA Comments at 52 ("EPSA asserts, and the attached Hogan Policy Paper supports, [citation omitted] that LMP minus avoided costs for generation or the retail rate ensures that demand response is economically efficient . . . ").

[58] *See* Kahn Reply Affidavit at 23-25.

[59] *Id.* at 24.

ticulated another way, while state regulators have the ability to approve state-specific demand response programs and approve changes to retail rates, such authority is not so great that it can be exercised to impede or undercut this Commission's statutory authority to ensure that demand response participation and compensation opportunities exist, given how demand response affects wholesale electricity markets. As recently as Order 719-A, the Commission properly staked out its jurisdiction over demand response as a practice that affects wholesale rates and markets.[60] Notably, Order 719 is now a final and non-appealable order, as no party petitioned for review of the Order, including the Commission's jurisdictional claim. Given the Commission's claimed jurisdiction over demand response as a practice affecting wholesale rates, any state regulatory actions to frustrate or undermine FERC's jurisdiction should not be condoned.[61]

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[60] Order 719-A at P. 47.

[61] *See Arkansas Louisiana Gas Co. v. FERC*, 453 U.S. 571, 580 (1981)(finding that the Commission had authority over interstate sales and wholesale electricity rates and that states and state laws could not interfere); *see also Natahala Power and Light v. Thornburg*, 476 U.S. 953, 966 (1986)(stating that only where Congress has explicitly provided an exception to the power granted to the Commission, states may not interfere but, a "State must rather give effect to Congress' desire to give FERC plenary authority over interstate wholesale rates, and to ensure that the States do not interfere with this authority.).

2. The Commission's Authority Over Practices Affecting Wholesale Rates Does Not Require It To Look "Behind-the-Meter."

Despite the express language in the Federal Power Act granting the Commission jurisdiction over *wholesale* rates, some parties in this proceeding also claim that the NOPR would lead to a "perverse economic incentive" for load to enter into agreements to take generation behind the meter when possible, thereby meeting load energy obligations outside of the RTO market while also being paid LMP by other consumers in the RTO for the load reduction on its system.[62] It has also been argued that, while an industrial customer has every right to self-generate, paying LMP to such a customer provides a cross-subsidy.[63]

The Commission's jurisdiction extends only to the rates for sales of electric energy for resale in interstate commerce, and to practices that reasonably affect those rates. The Commission has recognized that metered reductions in demand impact wholesale clearing prices. However, the Commission has not taken the next step, and would be overstepping its authority if it took the next step, of dictating or limiting the way in which retail customers are able to reduce their reliance on grid-based supply to the benefit of other customers. It is true that, in limited circumstances, the Commission has weighed in on discreet

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[62] *Id.* at 7, 59-60; ICC Comments at 12.

[63] *Id.* at 60.

behind-the-meter-generation issues. These instances, however, often involve how RTOs can treat behind-the-meter-generation for load forecasting purposes—i.e., precisely how behind-the-meter generation impacts metered electrical demand.[64] The Commission also addressed behind-the-meter-generation in Order 2003,[65] where the Commission declined to apply rules regarding interconnection agreements and procedures to behind-the-meter-generators that are not engaged in the sale-for-resale of electricity in interstate commerce, in recognition of the Commission's jurisdictional limits.[66] The Commission's decision in that proceeding demonstrates the understanding that generation behind the retail meter and serving a customer's own load does not affect interstate commerce, is beyond the Commission's jurisdiction, and should not be subject to Commission requirements.

Suggestions now to include as part of a Rulemaking a peek behind the curtain of metered electrical demand, and suggestions that compensation be adjusted if that peeks reveals use of behind-the-meter generation, not only unlawfully stretch the Commission's

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[64] *See Midwest Indep. Transmission Sys. Operator*, 126 FERC ¶ 61,143 (2009)(finding that behind-the-meter-generation cannot be "netted" for load forecasting purposes; *Cal. Indep. Sys. Operator Corp.*, 104 FERC ¶ 61,062 (2003)(allowing "netting"); *PJM Interconnection, Inc.*, 107 FERC ¶ 61,113 (2004) (allowing netting).

[65] *Standardization of Generator Interconnection Agreements and Procedures*, 104 FERC ¶ 61,103 (2003).

[66] *Id.* at P. 804.

jurisdiction, but also subvert the objective of ensuring efficient reductions in the demands placed on the system. The fact of the matter is that a demand-response resource actively participating in the wholesale market will provide the same benefits to the market regardless of whether those benefits are made possible by turning off an industrial process, or increasing the output of on-site cogeneration equipment, or some combination of the two. Peeking beyond metered electrical demand would also be akin to FERC looking behind a wholesale generator's meter and adjusting compensation based on how the generator makes itself available for supply to the grid. Again, if the suggestion is carried to its logical conclusion, those making the suggestion end up in a place where they do not want to be. To avoid these problems, the Commission should continue to restrict the scope of this Rulemaking to the wholesale energy market and establish compensation mechanisms that pay out based only on changes in metered electrical demand. How or why that metered electrical demand changes are irrelevant.

F. Demand Response Must Have Opportunities To Participate In Wholesale Energy Markets Without Discrimination Or Barriers To Participation.

PJM's Market Monitor opines that the ultimate solution to removing barriers to demand response will require not just adequate compensation, which represents only a "small part" of the problem, but also the ability for customers to see and react to price sig-

nals.[67] For its part, EPSA states that the NOPR incorrectly attempts to resolve retail market barriers to demand response participation (i.e., lack of dynamic pricing) through a wholesale pricing fix.[68]

The Commission should recognize that PJM's Market Monitor and EPSA, among others, have the situation completely backwards. It is in fact the need to rectify *wholesale* pricing levels for demand response resources that should drive this Rulemaking. Retail rates would then need to conform so as not to subvert the Commission's objectives. Characterization of the NOPR as attempting to resolve retail market barriers to demand response resources misses the entire point of the Commission's initiative. Retail market barriers are not the focus and were appropriately not mentioned in the NOPR as a basis for the Commission's action. The real point is that both demand and supply-side resources must be given an opportunity to participate as dynamic elements of the wholesale market. The objective is not necessarily to remove barriers, but rather to enable efficiency-improving participation. The NOPR appropriately recognizes this *wholesale* market issue, and correctly resolves to address the issue by equilibrating compensation between supply-side and demand-side resources.

The belief that "dynamic pricing" is the ultimate solution also fails because it ignores the impact of real-

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[67] Monitoring Analytics Comments at 5-6.

[68] EPSA Answer at 24.

world circumstances on the economic theory. While the concept of dynamic pricing can, to some degree, be intellectually appealing and should be explored on a voluntary basis for customers that choose to participate, actually *requiring* dynamic pricing would have far different results.[69] As Dr. Kahn observes, the model envisioned by the NOPR would allow demand response aggregators to offer the functional equivalent of dynamic retail pricing, but to do so only for those customers who want it and only when they want it. In this sense the practical result being pursued in the NOPR is far superior to the theoretical panacea offered by Dr. Hogan and others.[70]

It is no surprise or secret that business customers need certainty in order to make forward-looking and sound purchasing decisions. Mandatory dynamic pricing would add significant uncertainty in that, under an approach that would expose all customers to "dynamic" rates, customers could not adequately plan and make business decisions. In all likelihood, mandatory "dynamic" pricing would cause customers to enter into various arrangements to hedge against higher and more variable costs, completely undermining both the reason for the dynamic rates and the intended results. The Commission should reject pro-

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[69] As Dr. Kahn demonstrates in his Reply Affidavit, dynamic pricing is problematic for both economic and political reasons, both owing to the high costs associated with and occasioned by such a pricing model. *See* Kahn Reply Affidavit at 5.

[70] *Id.* at 21.

posals that would mandate dynamic pricing for customers and, instead, continue down the path of implementing the more practical solution of compensating demand response participation.

G. Adequate Measurement And Verification Protocols Are Currently In Place In Most Markets—This Issue Should Not Be Erected As A Further Barrier To Progress On Demand Response Compensation.

EPSA contends that the NOPR proposes enhanced compensation for vaguely defined "demand response," while North American Energy Standards Board ("NAESB") and North American Electric Reliability Council ("NERC")[71] processes are underway to establish standards defining demand response products and accurately measure demand response.[72] According to EPSA, therefore, any consideration of any standardized pricing mechanism must await the successful implementation of measurability and verification ("M&V") tools that ensure that demand-side resources can and will perform when required.[73]

Contrary to EPSA's concerns, there is no need for the Commission to delay its implementation of the pro-

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[71] Some Demand Response Supporters' members serve on NERC committees and are unaware of any processes that are underway to establish NERC measurement and verification standards.

[72] EPSA Comments at 6, 28-31.

[73] *Id.*

posed Rule until completion of any processes that may be underway at NERC or NAESB. First, the current proceeding is meant to determine the proper compensation for demand response in FERC-jurisdictional markets. Uniform M&V standards, while perhaps ultimately desirable, are simply beyond the scope of this proceeding and not necessary to effectuate correct compensation for demand response resources. Second, most RTOs already have in place some M&V rules to ensure that claimed load reductions occur as reported. Consider:

- PJM Operating Agreement at section 3.3A.2;
- CAISO Demand Response Resource Guide, Guide to Participation in MRTU Release 1 (Nov. 29, 2007), Version 3.0;
- ISO-NE Manual for Measurement and Verification of Demand Resource Value for Demand Response, M-MVDR, Revision 2 (June 1, 2010);
- Midwest ISO Business Practice Manual MO-BPM-4.8 (considered by Demand Response Working Group June 7, 2010);
- NYISO Day-Ahead Demand Response Program Manuals (June 2003), NYISO Emergency Demand Response Manuals (July 2008);
- SPP is, reportedly, currently considering M&V protocols in response to Order 719.

At some point, the Commission may consider standardizing M&V rules and protocols across all organized

wholesale markets. However, such a step is simply not necessary to promulgation of a Final Rule in this proceeding.

H. Demand Response Provides A Comparable Service To Generation In Organized Wholesale Electric Markets.

Several parties voice concerns that the NOPR incorrectly assumes that one MW of demand always equals one MW of supply under all conditions.[74] According to EPSA, for example, demand response resources simply are not "full" substitutes based on the nature of their participation and the rules applicable to each resource in the energy markets.[75] PPL Parties assert that, while generation that is dispatchable by an RTO can be relied upon for planning, operational security, and reliability purposes, an RTO cannot count on the voluntary product that is provided by demand response in the same way.[76] EEI states that demand response cannot be comparable to generation because demand response does not deliver energy.[77]

A demand reduction of one MW and a supply addition of one MW are not necessarily *identical* in all respects. However, they are directly comparable in the way each can affect the equilibrium of supply and

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[74] *See, e.g.* EPSA Comments at 70-77; P3 Comments at 25-27; Comments of the PPL Parties at 9.

[75] EPSA Comments at 70-77.

[76] Comments of the PPL Parties at 9.

[77] Comments of Edison Electric Institute at 15.

demand on the wholesale grid. As Demand Response Supporters pointed out in Initial Comments, reducing consumption is comparable to increasing generation because demand response provides a service that is equivalent to the service provided by generation—i.e., providing the service of demand response enables grid operators to maintain the necessary system balance between supply and demand.

Furthermore, in his Reply Affidavit, Dr. Kahn succinctly adds that "demand response (DR) is in all essential respects economically equivalent to supply response."[78] Dr. Kahn writes that demand response is equivalent to supply response because for all resources, "energy saved [is] equivalent[] to energy supplied," and should be regarded equivalently as a resource proffered in competitive power markets.[79]

In addition, the comparability between generation and demand resources with respect to supply and demand balancing has been noted by several independent agencies, including the Commission's Staff.[80] Indeed, several parties, in their respective Comments in this proceeding, acknowledge that de-

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[78] Kahn Reply Affidavit at 2.

[79] *Id.*

[80] *See, e.g.*, Federal Energy Regulatory Commission, *Assessment of Demand Response and Advanced Metering: Staff Report*, Docket No. AD-06-2-000 (Aug. 2006); Federal Energy Regulatory Commission, *Assessment of Demand Response and Advanced Metering: Staff Report*, Docket No. AD (Dec. 2008)("2008 Staff Report").

mand response provides a functionality that is "comparable" to the functionality provided by generation.[81] The Commission should reject arguments to the contrary, and find that demand response provides a service that is comparable to the service provided by generation.

I. Setting The Correct Compensation For Economic Demand Response Does Not Implicate Reliability Issues.

At issue in this Rulemaking is the determination of the correct level of compensation for demand response provided in organized energy markets. In an effort to change the focus of this rulemaking and, ultimately, to dissuade the Commission from taking steps to facilitate more demand response, some commenters resort to "playing the R card." They claim that full LMP compensation for demand response could somehow adversely impact system reliability. For example, one such commenter argues that "[a]t some level of

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[81] *See, e.g.*, Comments of Consolidated Edison Solutions, Inc. and Consolidated Edison Energy, Inc. at 1 ("The simple answer is yes, that a reduction in consumption is comparable to an increase in generation, but the question is academic."); Comment of the New York State Public Service Commission at 10 ("The two market changes are comparable, but demand response may be preferable to supply stimulation due to externalities that are not included in the price of generation."); Comments of the Edison Electric Institute at 14 ("From the perspective of balancing supply and demand, a reduction in consumption is comparable to an increase in production.").

market share," demand response could "severely hamper[] the reliable delivery of electricity that is needed by consumers"[82] and that demand response is an "imperfect substitute[] for produced MWhs from a reliability perspective."[83] The commenter further contends that there is a "point of electricity demand below which consumers will not go economically if acting on accurate price signals."[84] The comments go so far to say that demand response is "inconsistent with reliability."[85]

Demand Response Supporters object to efforts to introduce, as part of this proceeding, reliability issues that are simply irrelevant to the issues at hand. The Commission should reject these efforts, for several reasons.

First, the Commission did not raise reliability issues or seek comments on reliability issues as part of this NOPR. The NOPR concerns itself only with the correct level of compensation necessary to attract greater amounts of demand response in the day-ahead and real-time energy markets in ISO and RTO regions. Nothing more. In fact, the Commission made clear in the NOPR that demand response participation in capacity mechanisms and under rules that address resource adequacy are *not* in play in this proceed-

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[82] EPSA Comments at 71.

[83] P3 Comments at 34.

[84] EPSA Comments at 70.

[85] *Id.*

ing.[86] There will be no shortage of available supply under an economic demand response mechanism, and many of the commenters' concerns are fundamentally rooted in resource adequacy, and capacity, market structures. They are simply irrelevant to this proceeding.

Second, to the extent that generators' concerns stem from the availability of supply to meet demand, it should be noted that RTOs already have in place various detailed rules and mechanisms to meet instances of unexpected loss of supply in reserve and other markets. For example, if for some reason a participating demand response resource could not or did not respond adequately, the RTO or relevant authority would simply redispatch other resources to meet anticipated load. In a demonstration of the comparability of demand- and supply-side resources, the same response would be deployed if *generation* experienced a forced outage when it was otherwise economic for the resource to produce energy in the real-time market.

Interestingly, some of the same commenters that theorize about demand-side resources creating reliability problems are the same parties that fought for, and won approval from, the Commission to have the right to deactivate generation from organized markets with minimal notice.[87] Their efforts to inject reliabil-

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[86] NOPR at P. 7.

[87] *See, e.g., PJM Interconnection, LLC,* 110 FERC ¶ 61,053 (2005), *order on reh'g* 112 FERC ¶ 61,031 (2005); *see also PJM*

ity issues into this Rulemaking, which concerns itself only with appropriate levels of compensation for demand resources, should not be countenanced. To the contrary, the Commission has recognized and can rest assured that demand response actually fosters greater reliability in wholesale markets.[88] Reliability is simply not an issue here.

Interconnection, LLC, EL03-236-001, Request for Clarification or, in the Alternative, Rehearing of the Electric Power Supply Association at 3-4, in which EPSA reminds the Commission that PJM does not have "the authority to require generators to operate beyond a reasonable notice period," but instead must provide for a limited time period during which "a unit is required to operate under this deactivation structure."

[88] NOPR at 5 (citing "ISO-RTO Council Report, Harnessing the Power of Demand—How ISOs and RTOs Are Integrating Demand Response into Wholesale Electricity Markets" at 4, http://www.isorto.org/atf/cf/%7B5B4E85C6-7EAC-40A0-8DC3003829518EBD%7D/IRC_DR_Report_101607.pdf) ("Demand response contributes to maintaining system reliability. Lower electric load when supply is especially tight reduces the likelihood of load shedding. Improvements in reliability mean that many circumstances that otherwise result in forced outages and rolling blackouts are averted, resulting in substantial financial savings. . "); "*Smart Grid Policy*," 126 FERC ¶ 61,253, at P. 19 and n.23 (2009) ("The Smart Grid concept envisions a power system architecture that permits two-way communication between the grid and essentially all devices that connect to it, ultimately all the way down to large consumer appliances. Once that is achieved, a significant proportion of electric load could become an important resource to the electric system, able to respond automatically to *customer-selected* price or dispatch signals delivered over the Smart Grid

III. CONCLUSION

WHEREFORE, the Demand Response Supporters respectfully request that the Commission consider these Reply Comments and, in a Final Rule, adopt regulations requiring the payment of market-clearing prices in all hours and across all regions for demand response in organized wholesale energy markets.

Respectfully submitted,

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Dated: Aug. 30, 2010

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infrastructure without significant degradation of service quality.") (emphasis added).

UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. RM10-17-000

DEMAND RESPONSE COMPENSATION IN ORGANIZED
WHOLESALE MARKETS

Aug. 30, 2010

I am Alfred E. Kahn, Robert Julius Thorne Professor of Political Economy, Emeritus, at Cornell University; and Special Consultant to National Economic Research Associates, Inc. (NERA).

The purpose of this testimony is to respond to criticisms of my previous testimony in the PJM proceeding which preceded this NOPR, dated September 15, 2009 but is now part of the record in this NOPR proceeding.

Although there are a number of these comments with which I disagree in one respect or another, I feel constrained—in the interest of minimizing the burden on the Commission and in recognition of the delay in submitting this paper caused by my own recent indisposition—to focus on two lines of argument: the failure of Professor William Hogan and Mr. Robert Borlick to recognize the especial significance—critical in my opinion—of one strand of the economic principles to which we all subscribe—namely, their applicability

to an industry critically subject to diminishing returns (or increasing costs, statically)—and their misapprehensions of one thread of the economic argument and a key regulatory issue which, as far as I can tell, they have overlooked in their comments.

Before discussing specific issues associated with its effectuation, I submit they have given insufficient weight to the proposition—in principle indisputable—that demand response (DR) is in all essential respects economically equivalent to supply response; and that economic efficiency requires, as the NOPR recognizes, that it should be rewarded with the same LMP that clears the market. Since DR is actually—and not merely metaphorically—equivalent to supply response, economic efficiency requires that it be regarded and rewarded, equivalently, as a resource proffered to system operators[1], and be treated equivalently to generation in competitive power markets. That is, all resources—energy saved equivalently to energy supplied—the two blades of a pair of scissors in the familiar metaphor—that bid lower than the LMP should receive the same market-clearing LMP in remuneration.

The concerns expressed (and hypothetical exemplars cited) in comments opposing the Commission's

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[1] Recognition that the practical task of ensuring that a proffered "negawatt" is actually delivered is beyond the scope of this proceeding, but not—I suggest—inseparable from a decision on the merits of the proposal.

proposal are uniformly based—consciously or unconsciously—on the conception that the Commission should be guided in setting these wholesale rates by—actual or potential—inefficiencies in retail markets. Although there is a perfectly respectable economic "theory of the second-best", pointing out that in a world in which prices—particularly of complements or substitutes—are not uniformly set at "first-best"—that is, marginal cost—levels, it may well be inefficient to set particular prices—especially of complements or substitutes—at "first-best" levels. The Commission's mandate to set "just and reasonable" rates is generally understood to translate the adjectival qualification as "just and reasonable" into "efficient" or "cost-related". For a putatively expert Commission, disproportionately influential among former Commissions, to interpret its mandate as equivalent to political correctness, to desert the additional conception of "just and reasonable" as economically efficient or cost-justified would be, I suggest, madness. They would ignore the proper scope of the Commission's regulatory responsibilities, the fact that the great majority of retail rate designs are economically inefficient, and that it is retail rates that should not be permitted to undermine efficient wholesale rates rather than the reverse.

THE RELEVANT ECONOMICS

I begin with the rebuttal testimony of Mr. Robert Borlick, because its generous appreciation and reproduction of my expositions of the case for marginal cost pricing four decades ago provides the logical basis for

demonstrating here that my previous recommendations were not only in full accord with those principles but that he and Professor Hogan have both overlooked its strikingly direct implications for the issues here before us: They provide the basis for demonstrating the especial relevance of the phenomenon of diminishing returns or increasing unit costs (as output is higher)—which also, incidentally, demonstrates the irrelevance of Professor Hogan's example of the retail purchase of shoes, which so far as I know is subject to no such systemic tendency.

Few industries better illustrate the virtues of marginal cost pricing—as those costs per unit go up and down as output does the same, in the transitions from night to morning to evening and back to night, as well as seasonally and cyclically, and marginal costs change correspondingly—most dramatically as demand approaches—and with it the possibility of system-wide failure—their annual peak (for example, after a succession of the hottest summer or coldest winter days.

The *greatest remaining obstacles* and the simple rationale for the FERC's proposal for achieving such first-best efficiency by directly confronting all purchasers of electric power with prices fluctuating corresponding to market conditions are a combination of economics and politics—the high costs—prohibitively high for most—of the complex metering necessary to charge prices that vary directly with those fluctuating marginal costs by time-of-day and season-of-the-year and—as Mr. Borlick also emphasizes—the reluctance

of state regulatory commissions, reflecting a populist distaste, to charge customers for their usage—to which I have already referred.

Mr. Borlick and Professor Hogan both implicitly or explicitly accuse me of naïveté or ignorance in linking the absence of universal time-of-day metering to the threat of system-wide breakdown and—even more pertinent to the issue before us here—how best to facilitate efficient demand response to efficient electricity pricing. As Mr. Borlick asserts:

> Most of the benefits of economic demand response are achievable through the participation of a small subset of the large commercial and industrial customers who already have interval meters installed. *[footnote reference omitted]* Furthermore, *the cost of installing interval meters* for such large customers is *negligible compared to the potential savings* available to them through their participation in PJM's Economic Demand Response Program without subsidy payments. These are big boys who don't need to have their profits enhanced *at the expense of small customers*. (Page 3, stress supplied)

I have no basis for questioning the factual accuracy of that assertion, echoed also by Professor Hogan.

But I emphatically question their similarly-based minimizations of the likely beneficial consequences of what they consistently refer to as "subsidizations" at issue in these proceedings, or what Hogan character-

izes as double compensation—once in the savings consequent on the reductions in purchases by participants in the FERC program and, second, compensation from the pool to successful demand-reduction bidders.

Mr. Borlick's confident assertion, however, answers the wrong question. The question is not what portion of the economically efficient demand reduction is achieved today "by the small subset of the largest . . . customers who already have interval meters installed." The pertinent question is: What is the amount or fraction of potential consumption that practitioners of conservation could save but for the obstacle of the expense of the requisite meters, *but remains economically achievable in other ways*, and *specifically by a program such as the one before us?*

The Subsidization Issue

Before addressing myself to that question, it is logically necessary to respond to Mr. Borlick, Professor Hogan and comments of the Electric Power Supply Association (EPSA), in particular, their characterization of the plan, consistently and repeatedly, as involving a "subsidization", with the clear implication that it inefficiently distorts consumer and producer choices, producing an economically inefficient allocation of resources, at the ultimate cost to consumers at large.

I emphatically respond:

- Mr. Borlick's criticisms are internally inconsistent. If, as I have no basis for doubting, "the costs of installing interval meters for such large customers

is negligible compared with the potential savings available", how can that fact refute the possibly large additional benefits of the FERC proposal, which is directed at consumers whose usage *individually* is too small to be considered for such metering, but who may nevertheless collectively present large opportunities for efficient conservation?

- And how (and why) exactly would the FERC proposed plan alter the present situation to the benefit of the 'big boys' at the expense of the little ones? And even if it did, why is that a reason for an economist who begins his testimony with a tribute to marginal cost pricing to oppose it?

- I have no way of assessing the total amount of efficient demand curtailment as yet unexploited. I can only surmise from, for example, Mr. Borlick's attribution of huge possible savings exploitable by very large users, that, while of course the comparable savings by small users in the presence of time-of-day metering and tariffs would be individually only a small fraction of that, in the aggregate they would be enormous. In any event, ultimately the only way of ascertaining the presence or absence of such opportunities will be to adopt the FERC plan and let the market tell us. I observe, in this connection, that part of the rationale for a previous proceeding on this issue (Docket No. EL09-68-000) was PJM's dissatisfaction with the amount of demand response it had

achieved under the scheme that Mr. Borlick supports.

- Whatever the size of the likely response, it is *simply incorrect to label the remuneration of successful bidders* contemplated in the present proposal as "*subsidies*", rather than, for example, *investments*—without regard to whether the economic benefits of the consequent reduction in energy use exceed the costs in present value terms, or, indeed, than consumer expenditures for electric power itself, likewise supplied through competitive auctions.

- The purpose and essence of the program proposed in the NOPR is to encourage the development and to finance only economically efficient demand response efforts—comparing achieved saving with its costs, both in present value terms—that is to say, limited to the (marginal) costs that would be saved by their efforts if successful.

The Protective Role of Competition

- The program would achieve these results as efficiently as possible, pitting offers to supply KWh against one another and against offers to save them, in open competition.

- Does the plan involve inefficient "subsidization" of demand response, as the opposition routinely assert? No—it does set up an arrangement that treats proffered reductions in demand on a competitive par with positive supplies; but the one is

no more a subsidy than the other: the one delivers electric power to users at marginal costs—the other—reductions in cost—both at competitively-determined levels. Obviously, it would be nice if the following were also true: both incremental supplies and reductions in energy use would be compensated only upon certified delivery of the promised benefits (but that legitimate consideration[2] is beyond the scope of this enquiry).

- Does this plan involve double compensation, as Professor Hogan asserts, at the expense of power generators—of successful bidders promising to induce efficient demand curtailment and of consumers induced to practice it? Certainly not: the decrease in the revenue of the generators is (and consequent savings by consumers are) *matched by the savings in their (marginal) costs of generating that power*; the successful bidders for the opportunity to induce that consumer response are compensated for the costs of those efforts by the pool, *whose (marginal) costs they save* by assisting consumers to reduce their purchases. It sounds as though opponents to the NOPR proposal expect the plan to confer these savings on consumers at no charge. On the contrary: the competition for remuneration by the pool would be expected to put

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[2] I assume that the ISO will have correctly measured the MWh that would have been consumed but for the DR program. It is clearly possible to subsidize someone by paying him something for nothing. But I have assumed this problem has been solved.

pressure on the bidders to extract as much as possible of the promised frequent savings for the beneficiaries.

- As to the remuneration of the successful bidders, promising reductions in purchases of power from the generators, their compensation from the pool itself is offset by the savings in (marginal) costs induced by their—successful—efforts to promote efficient demand response: that remuneration is emphatically not a net burden on generators (and not a subsidy), because it matches the savings in marginal generating costs that their successful efforts induce.
- Observe that under effective competition, those middlemen are paid only once, not twice. To the extent they incur costs in inducing the demand response they promise, they will expect to retrieve them, profitably, from a combination of charges to consumers whose bills they have reduced and from the pool—the latter reflecting the savings in marginal generation costs they have effected.
- For those suppliers with infra-marginal generators, it is true that the rent that they would capture is greater without any demand response that acts to lower the market-clearing price. But that situation is identical to the introduction of a lower cost generation resource and is the efficient outcome in a competitive market—inuring to the benefit of all remaining customers.

Competition (and competitive bidding in the auction market) may be relied upon to prevent exploitative double charging—of power generators, on the one side, and consumers whose bills they helped reduce, on the other.

That electricity generators have opposed this plan should not be surprising: their primary business is to sell power not to encourage its conservation, and I have myself publicly cited evidence that they reap the preponderance of their profits on those occasions when demand is at its peak.[3] The fact remains that—to the extent they are subject to effective competition—their revenue losses will be matched by the reductions in the high marginal costs of generating that power.

The Danger of False Analogies and Usefulness of Valid Ones (however extreme)

Because it illustrates my argument so clearly, I cannot refrain from observing once again the uncharacteristic irrelevance of Professor Hogan's analogy to the purchase and sale of shoes. He might with far greater relevance have referred to the auctions of Rembrandt paintings: The former has none of the directly relevant characteristics of steeply increasing marginal supply or opportunity costs at times of peak demand—in consequence of which *all other purchasers benefit*

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[3] "The Adequacy of Prospective Returns on Generation Investments under Price Control Mechanisms," *The Electricity Journal*, 15:2, March 2002, pp. 37-46.

directly from restraint in the demand of any one of them.

Overcoming the Obstacles to Efficient Choice

In sum, the arrangements at issue in these proceedings would tend to overcome the obstacles to efficient consumer choices posed by not only the high cost and political resistance to the adoption of the requisite complex metering but also a widespread lack of expertise among consumers in adopting consumption habits tailored to the individual circumstances of each, enlisting competition to achieve those goals with maximum efficiency and benefit to the public at large, following the principles so lucidly (if I may be excused for so characterizing it!) expounded by Mr. Borlick.

In consequence:

- The purchasing pool pays the minimum price necessary to satisfy the market demand—both directly in purchasing power from the competitive bidding generators and competitive providers of efficient conservation. And, in particular, the increases in marginal cost and price at times of relative scarcity or rising marginal costs will be moderated by the response of intermediaries to the LMP reward for assisting consumers to respond efficiently. And, observe, no one is subsidized. As in all markets —perfectly-, imperfectly- or not-at-all competitive, infra-marginal sellers—willing to sell at prices lower than the one necessary to clear

the market—and supra-marginal buyers—willing, if necessary, to buy at prices higher than the one that clears the market—are the beneficiaries of economic rents.

- As I have already pointed out, Mr. Borlick correctly cites the reluctance of most state public utility commissions to "subject retail customers to real-time market prices" as reinforcing the barrier of costs and lack of consumer expertise. The design in the NOPR can tend only to offset or circumvent the barriers by offering the middlemen the incentive and wherewithal to secure the voluntary participation of customers by helping them to offset these barriers to efficient choices with technical and financial assistance. As I have argued, so long as those "bribes" do not exceed the LMP saved by the voluntary participations of consumers and third-party facilitators, no additional "net benefit test"—such as has been set for comments by the Commission—is required.

As to the characterization of the remunerations of the participants in the program as "subsidies"—they are no more subsidies than the remunerations of generators for the power they actually sell: the direct payments here are no greater than the LMPs that participants in the program—and non-participants together—save by the efforts of the former: *In an industry subject to increasing costs*, any and all efforts to promote curtailment in customer's demands on the system—by pre-arrangement or other—*confer benefits upon all consumers*—participants and non-

participants alike—while retarding the growth in economic rents accruing to generators (which may explain the opposition of generators to the program) by retarding the recourse of all suppliers to higher marginal cost generation.

Response to Professor Hogan's Criticisms

It is with considerable diffidence that I undertake to rebut the testimony of Professor Hogan. On the other hand, I strongly disagree with his negative assessments of the efforts at issue here to overcome the very large imperfections in the price signals to purchasers of electric power and the consequent need—undeniable, in my opinion—for governmental intervention to see to it that demand is efficiently responsive to marginal supply costs by offsetting institutional obstacles to such rational behavior—by treating promises to reduce purchases equivalently with bids to supply power.

There are several ways of responding:

- Successful demand-side bidders—that is to say, enterprises that offer to and do reduce power consumption—should be rewarded in the same way as supply-side ones—receiving the market-clearing price insofar as they do what they promise to do—reducing a burden of demand on the system—and by so doing, holding down or reducing rates to all customers.
- This is assured by the bidding process, in consequence of which the compensation for the

promised—and realized—reduction in demand are credited with the costs that that consumption would have imposed on the system, thereby *reducing costs to all residual customers* (the price assured by the bidding process).

- Successful demand-side bidders benefit all residual customers by holding down, or moving back along the steeply rising marginal cost function, the marginal cost of serving them by either reducing the increase in demand or absolutely reducing demand.
- Finally, and I suspect most congenial with Professor Hogan's pioneering advocacy of competitive power markets, any increase in the efficient responsiveness of demand (to prices competitively determined, as in the ISO-conducted auctions) will move us in the direction of correcting the most severe deficiency in most such markets in the US, the lack of an adequately, price-responsive demand side.

In short, Professor Hogan's criticism is uncharacteristically grounded in a particularly static conception of the electricity supply industry, in which competition (or the selective entry of alternative ways of serving the market) is not permitted to affect the previous balance of mark-ups over direct costs. And in which the solicitation and facilitation of alternative ways of satisfying the need for electric power and/or satisfying demand—including providing customers with economically efficient ways of reducing their consumption in

response to price increases (especially on peak) by rewarding them with the permitted to disturb the previous fine balance of regulated rates and book (as distinguished from economic) costs.

Ironically, Professor Hogan's language itself betrays a purely regulatory philosophy. For example, assertedly as a result of the Commission's proposals,

> "certain consumers would be paid subsidies that are inconsistent with economic efficiency." (page 2)

I do not see how the pool's paying customers of incumbent suppliers the marginal costs they save the system by turning to alternative suppliers or better economizing in their use of electric power—that is to say, reimbursing them with the costs that they save the system by so doing—can ever be inefficient, if only dynamically. His reference to the payments to customers withdrawing their patronage as "subsidies"—when what is at issue is rewarding them with the marginal costs that they *save* the system—makes no sense at all except in an anti-competitive, purely static system of franchised, regulated monopoly utilities—which I do not believe Professor Hogan intends to recommend.

To characterize as "subsidies" payments by power pools to winning bidders in open competition between their offerings and those of traditional suppliers of kilowatts in competition with one another quite simply excludes them from a healthy, efficient competitive process—subject, of course, to ensure in the case of both successful competitive bidders that they deliver

on their promises. In both cases, the marginal costs that they either deliver or save shall bring down the costs of the winning bidders and in both cases are properly recovered from the common pool.

Professor Hogan's assertion to the contrary (in his testimony, p. 2):

> "The increase in costs resulting from the need to pay for these subsidies will encourage consumers to purchase their electricity outside of the RTO "

is bad arithmetic: it ignores the fact that the payments that he refers to again as "subsidies" are merely marginal costs *paid* by the successfully bidding "negawatt" buyers.

How can "costs" be "increased" by remunerating conservers of energy with the incremental costs that they would otherwise impose on the system?

There is a certain irony in his emphasizing, at the very outset of his testimony, that FERC's proposed plan would not apply to two groups of customers who already have the opportunity to refrain from consuming power and be rewarded with the prevailing high and rising market price, when his testimony opposes extending that *same* opportunity to whatever group of consumers can be assembled to make that same choice —namely, surrendering their right to be served by franchised marketers, receiving in exchange the "first-best" market equilibrating price.

Opponents of the proposal will presumably respond with the assertions that I have already disposed of—namely, that the new competitive arrangements will be "subsidized" by the incumbent generators of power—in contrast with Professor Hogan's approval of the voluntary transitions he initially cites.

Charging the pool—ultimately some power generators—the cost of marshalling demand response is, however, no less a reasonable cost of operation than the cost of the clerk and register in Professor Hogan's shoe store; and it is matched by the LMP of generating the power that it saves the pool. In order to fulfill their successful bids, these intermediaries work directly with end users to develop peak-shaving programs, sharing with them the proceeds of their successful bids and subject to severe penalties if they fail to deliver on those promises. In some cases electric power companies themselves work directly with these intermediaries to produce the same results—a healthy competition. Their resulting rewards are in no sense a burden on either the generating company or the public, but are financed by the LMP savings of the generators.

Of course, there is an element of strangeness in a supplier being required to reimburse a customer for refraining from purchasing from it. But:

- there is a legal obligation to serve the customer, and

- in a situation in which an increment in consumption has the external effect of increasing the cost of service to other customers, and there is a social interest in encouraging energy conservation, it is perfectly reasonable for society to encourage enterprises themselves to induce conservation by enabling customers to curtail their consumption and reward such efforts by requiring the franchised suppliers to reimburse such efforts out of their own dollar savings By so doing, they benefit all purchasers of power by holding down their rates.
- I should note that the first bullet point above reveals the error of those who are opposed to paying LMP for DR on the grounds that the customer who reduces consumption has not purchased anything. They go on to deduce that the customer has nothing to sell to the market and shouldn't be paid full LMP for selling "nothing" But the obligation to serve creates an option to consume electricity that comes bundled with kWhs in the package of services that customers *purchase* from retail suppliers. And it is this option, bought and paid for, that the customer sells to the ISO or system operator. (Mr. Borlick recognizes that the option exists but erroneously dismisses the value of the option because he assumes that the retail supplier purchases the option when it is clearly the ISO/system operator purchasing resources to meet system load.)

THE REGULATORY ISSUE

Let me turn now to the regulatory issue which, to a former regulator, seems to dispose of the arguments against the NOPR proposal to pay LMP for DR—independently of the misapplications of economic theory I have discussed above.

Quite simply, Professor Hogan, Mr. Borlick and others arguing that the proposal contained in the NOPR should be rejected since they will lead to inefficiencies in the consumption decisions of retail customers ignore that the proper responsibility of the Commission is the justness and reasonableness of wholesale rates. The Commission's ambit clearly includes the well-being of the integrated grid and its operations, for example, by providing efficient incentives for demand response. But the Commission surely would be overstepping its bounds to attempt to ensure that wholesale rates rendered retail rates efficient. Indeed, that is transparently administratively infeasible given the plethora of state determined rates and the undeniable economic inefficiency of most of those rates. If the Commission tends to its own knitting, the approach it has set out in the NOPR is clearly the correct one. And the arguments based on the effects on retail customers of ISOs paying the economic price for demand response, are simply diversionary and irrelevant not to mention they stand the concept of federal preemption of wholesale tariffs on its head.

In seeking to make an efficient wholesale market, we must give deference to a State's conception of their

retail markets but only up to a point. And that point is where the State's actions do harm to the efforts of this Commission to maximize economic efficiency in the wholesale market. At the very best, a State substituting its vision of how DR should be remunerated for the economically efficient design put forth in the NOPR would do no harm to the effect of that design. If, as I fear most likely, the State's efforts to impose its view does diminish participation by DR suppliers—reducing the efficiency of the wholesale market in the process, the Federal obligation to make the wholesale market price efficient and thus just and reasonable must prevail.

The argument for efficiency, at best, is an argument that it is the responsibility of FERC to correct inefficiencies in the retail market through compensating inefficiencies of its own in some sort of attempt to implement a theory of the second best. But, like all theories of the second best, changes cannot be introduced piecemeal. If the Commission is to take this responsibility seriously (and they shouldn't) then they should compensate for *every* inefficiency in the retail sector—class of service boundaries, subsidies for other demand-side-management initiatives, renewable incentives, etc. For the lesson of the theory of the second best is that piecemeal adjustments to putatively improve efficiency may well worsen it unless all aspects of efficient consumption are taken into account. Professor Hogan's and the other similar pleadings to attempt to "correct" one aspect of retail inefficiency,

i.e., a failure to charge marginal cost rates should leave the Commission with no assurance that even if they sought to correct the inefficiencies of the retail market (which they shouldn't) that they had even taken a step in the right direction by divorcing compensation in the wholesale market from marginal cost for a particular selected group of suppliers.

AFFIDAVIT

Alfred E. Kahn, being duly sworn upon his oath, deposes and says:

1. I am a consultant to an intervenor in this proceeding, and I am duly authorized to make this Affidavit of Verification on its behalf.
2. I hereby verify that the statements of fact and other information contained in this Testimony are true and correct to the best of my knowledge, information, and belief.

/s/ ALFRED E. KAHN
ALFRED E. KAHN

Sworn and subscribed before me this 26th day of Aug., 2010

/s/ CYNTHIA PERNO
(Notary Public)

Cynthia Perno
Notary Public, District of Columbia
My Commission Expires 12/14/2014

UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. RM10-17-000

DEMAND RESPONSE COMPENSATION IN ORGANIZED
WHOLESALE ENERGY MARKETS TECHNICAL
CONFERENCE

Sept. 13, 2010
9:02 a.m.

APPEARANCES:

BEFORE:

DAVID HUNGER,
Office of Energy Policy Innovation

CAROLINE DALY,
Office of Energy Policy Innovation

ARNIE QUINN,
Office of Energy Policy Innovation

CARL PECHMAN,
Office of Energy Policy Innovation

JAMIE SIMLER,
Director, OEPI

MICHAEL MCLAUGHLIN,
Director, Office of Energy Market Regulation

MICHAEL GOLDENBERG,
Office of the General Counsel

HELEN DYSON,
Office of the General Counsel

ALSO PRESENT:

JON WELLINGHOFF,
Chairman, Federal Energy Regulatory Commission

PHILIP MOELLER,
Commissioner, FERC

JOHN NORRIS,
Commissioner, FERC

CYNTHIA A. LAFLEUR,
Commissioner, FERC

* * * * *

[5]

PROCEEDINGS

(9:02 a.m.)

MR. HUNTER: Okay, great. So thanks for coming. Before I introduce the first panel and go over today's format, I will start with a brief history of how we got to where we are today.

In March the Commission issued a Notice of Proposed Rulemaking regarding Demand Response compensation in organized wholesale energy markets. A number of comments were received, and many of the

commenters raised issues regarding the possibility of a Net Benefits' test, and also various methods of Cost Allocation for Demand Response compensation.

In order to get those items on the record, we issued another Supplemental Notice of Proposed Rulemaking in August and set up this conference here today within 45 days of that issuance. I think we're on day 38, so we made it in under 45. And we sought comments regarding those two issues, the Net Benefits test and Cost Allocation methodologies.

And so we are here today. There will be another round of comments within 30 days of this conference, which will be August 13th. Also, all of the statements from the speakers will be put on the record. So that can be part of what generates responses.

[6]

And let me explain the format. We've got a lot of speakers on two panels, one of Net Benefits this morning and the second one on Cost Allocation this afternoon. We also understand that there is some overlap between the two issues, so panelists on one panel may discuss issued related to the other panel.

And there is an implicit—I guess it is now explicit —assumption that the NOPR proposed to pay full LMP is in place, all this discussion is under that assumption. And thus the focus of the first panel is to discuss how the Commission could decide how to establish a test of the Net Benefits to determine whether the benefits associated with paying full LMP exceed

the costs. And if so, in what hours, and how that would be measured. We have already received a lot of comments on that.

And the focus of the second panel discussion is as to how to allocate the payment of Demand Response, assuming they're being paid the full LMP again.

* * * * *

[10]

MR. HUNTER: Okay. Thank you.

So with that, let me introduce our panelists and the Commission staff at the table, and then we can get going.

We have John Keene, Director of Regional and Federal Affairs for the Massachusetts Department of Public Utilities. We have Andy Ott, Senior Vice President for Markets at PJM. Robert Ethier, Vice President of Market Development, ISO New England.

Joel Newton, NextEra Energy. Saul Rigberg, attorney with the New York State Consumer Protection Board. We've got Audrey Zibelman, President and CEO of Viridity [11] Energy. Don Sipe, attorney representing Consumer Demand Response Initiative. Robert Weishaar, Jr., attorney for Demand Response Supporters. Paul Peterson, a consultant representing Public Interest Organizations. Stephen Sunderhauf, Manager of Program Design for Pepco Holdings.

And lastly, Roy Shanker, consultant representing PJM Power Providers Group.

And at the table for Commission Staff, we have Caroline Daly from the Office of Energy Policy Innovation; Michael Goldenberg from the General Counsel's Office; Arnie Quinn from the Office of Energy Policy Innovation; David Hunger, OEPI; Carl Pechman, also Office of Energy Policy Innovation; Jamie Simler, Director of the Office of Energy Policy Innovation; Michael McLaughlin, the Director of the Office of Energy Market Regulation; and Helen Dyson from the General Counsel's Office.

With that. I think we can begin.

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[18]

Andy Ott from PJM.

MR. OTT: Good morning. Thank you for the opportunity to appear before you to talk about this subject of benefits tests for Demand Response.

Clearly Demand Response provides benefits both to the wholesale market operation and to the regional grid operation. And in PJM we have seen nearly 10,000 megawatts of Demand Response resources clear in our Forward Capacity Auctions.

We have up to 16 percent of our Synchronized Reserve market that is supplied by Demand side resources. Although the amount of economic Demand

Response we've seen clearing in recent years, like this year for instance we're seeing around 100 megawatts of Demand Response clearing in certain hours, where two years ago it was more like 800 to 1000 megawatts. Even though we're seeing less of it clear, the amount registered and eligible to participate remains at levels above 2000 megawatts. So we're looking at some lower prices not providing the incentive to actually clear.

RTOs can of course develop metrics, benefits tests, to show the aggregate benefit of Demand side participation in the markets. We can estimate these [19] benefits again across time periods. I wouldn't want to get too granular, but monthly, seasonally, some type of static measures, from that perspective we certainly can do at reasonable cost. It would not be a costly thing to develop what I'll call aggregate benefits analyses. In fact, I think it would be beneficial to develop such a transparent mechanism that's relatively standard.

However, if you take—you have to use caution to actually take a benefits test and apply that to compensation, because you may have unintended consequences.

The implicit assumption in developing a benefits test for purposes of compensation would be that you could actually determine individual customers, whether they benefitted or not. That type of analysis would be very costly to implement. That would be cost-prohibitive to actually go down to a granular level to

assign value to an individual customers or individual time periods.

There's a couple of reasons for that. The first is just going and doing analysis on that granular level to essentially repeat market outcomes with and without Demand Response would be difficult to implement and costly.

The second, even if you were able to do that, then you have to assign benefit to individual customers. There's many other aspects of market positions that customers have—bilateral contracts they cleared in [20] different types of markets—and actually gathering that information and trying to attribute whether a price reduction would have been beneficial or not to a certain customer based on their hedging would be prohibitively even more costly to try to go gather that kind of information, which really isn't readily available for instance to RTOs.

In our previous comments, we've actually acknowledged, and I realize that a proposal to make direct payments to customers is not a simple answer. Certainly paying full LMP, LMP is the value in the market of Demand Response, but depending on the retail structure underneath the customer—in some cases, paying full LMP would be fine from the wholesale side. In other cases, it could pay full LMP from the wholesale side but may create unintended consequence because of the retail rate structure underneath.

So that issue we talked about in our previous comments and I won't continue.

I did want to talk a little bit about, though, price responsive demand as the next evolution, at least that we're discussing within the PJM market, which again is really automated customer response to innovative retail rates and enabling technology, of course. So that's two-way communication and the appropriate type of technology to [21] support those rates.

We've worked with states to develop an improvement to our Demand Response roadmap, and develop that type of document for people to use. We've worked within our stakeholder process to discuss the market rules under price response demand. Unfortunately that hasn't yet gotten consensus. There's a lot of competing interests there. We actually owe you a report, and we'll get that to you within a week or so based on a requirement we had to report on that progress.

But under PRD, energy would only be consumed by the customer if the market price was above LMP and they would see that directly because they're responding directly to that price through an innovative structure.

Probably the last point I would make is that, as we see this innovation moving forward—meaning the implementation of innovative rates and technologies—effectively what you will see here is that type of inno-

vation will drive customers to innovate in how they consume.

So I think it is better to put our efforts there. Because if you put your efforts there, you really don't need a Net Benefits test then, because you actually see the customers be directly incented through that.

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MR. ETHIER: Thanks for the opportunity to be here today.

First I would like to note that ISO New England is strongly support of Demand resources. We have approximately 2500 megawatts of Demand resources participating in our markets today, and we have recently implemented a state-of-the-art communications infrastructure that gives us real-time telemetry information from these resources and real-time communications with these resources. And we have found that has worked very well. And we continue to work hard to better integrate Demand resources into all of our markets.

I have three primary comments that I would like to make today, three primary points I would like to make today.

First is that the Net Benefits definition that we're talking about should match that of economic efficiency. So true Net Benefits are the difference between the

value consumers receive from energy and the cost of energy production. But Net Benefits are not equal to the consumer savings less payments for Demand Response.

So first, what's the definition of "Net [23] Benefits"? And our view is we believe it should coincide with our Tariff, and also with the definition of "economic efficiency."

Second, a Net Benefits test must consider all ISO administered markets. It shouldn't focus solely on the energy market because the markets interact. So price effects in the energy market have feedback effects in other markets, primarily the Capacity Market.

And then third, ISO New England has done some analysis in conjunction with the Brattle Group looking at the payment of the full LMP, both the payment of full LMP under various conditions, payment of LMP minus the retail rate, and real-time pricing; or by the baseline approaches. And we have looked at those things in the short run and in the long run to estimate Net Benefits from those circumstances.

And what we found is, paying the full LMP results in negative Net Benefits. Real-time pricing and LMP minus the retail rate results in positive Net Benefits. There will be a handout available, if folks would like to see sort of the details behind that study.

So first, ISO New England is committed to maximizing Net Benefits that are economically efficient. As I mentioned, our Tariff requires us to run economically

efficient markets, and we believe the definition is [24] consistent with the way economists define "economic efficiency," which is really the area between the Demand and the Supply Curves. We believe that is the appropriate way to define Net Benefits.

Second, and this is something that's easy to—well, I think the discussion to date has mainly focused on energy market effects, but it is clear the energy market isn't the only thing that would be affected by how you decide to pay price responsive Demand resources.

To the extent that paying these resources, and getting them engaged in the market reduces LMPs, that is going to have carry-on effects into the capacity market. Those effects are easy to describe.

For example, generation gets money from both the energy and the capacity markets. To the extent that energy market revenues decrease, they're going to increase the amount that they need to recover from the capacity market before they either enter the market, or before they retire from the market and de-list.

So those consequences are pretty clear, and we think that that's something that folks ought to consider when we calculate the Net Benefits of any system that we set up to pay price-responsive demands.

And third, we've taken a look at empirically what would happen if you implemented paying the full LMP and [25] these alternative structures that I've talked about?

We've really looked at five different approaches to price responsive demand.

The first one is: pay full LMP in all hours.

The second is: pay full LMP subject to an hourly Net Benefits test.

The third is: pay full LMP in high-priced hours, loosely speaking, the top 10 percent of the hours.

We looked at LMP minus the retail rate.

And we looked at real-time pricing, or by-the-baseline approaches.

As I mentioned, negative Net Benefits for the situations where you pay the full LMP; positive Net Benefits for when you pay either the LMP minus the retail rate, or when you have real-time pricing or by-the-baseline.

Speaking specifically on the Net Benefits test, the analysis I think is helpful in answering some questions. What it shows is the Net Benefits test is passed in the vast majority of the hours. So out of 8760, we were getting positive Net Benefits from some Demand reduction in 7600 hours.

What that says to me is—and that is looking at—sorry, and I need to be clear—that's on the consumer savings, if you implement the Net Benefits as a consumer savings test. What that says to me is, if your goal is to [26] pay full LMP and your test is consumer savings, don't bother with the Net Benefits test be-

cause it's not going to apply, and frankly it is not going to effectively limit the hours of operation at all, in case you get clearing in virtually all hours of the year.

And I can certainly talk in more detail about that in the Q&A section.

MR. HUNTER: All right. Thanks. Next up we've got Joel Newton representing the New England Power Generators Association.

MR. NEWTON: Thank you for the opportunity to participate in this panel. I will make two brief points by way of introduction.

First, the Net Benefits test is severely problematic. It sets forth a structure that will distort the decision of when to procure Demand Response. This distortion not only is inefficient but can equate to the exercise of buyer market power or market manipulation.

The core problem is that the Net Benefits test measures when to procure DR based on the overall effect the procurement decision will have in terms of suppressing energy prices marketwide.

This would determine Net Benefits in the short run to Load. In fact, the purported benefits are simply wealth transfers from suppliers to Load. This is not Just [27] and Reasonable under the Federal Power Act. Let me explain in more detail.

The proper way to conceptualize when to procure DR is that a particular consumer should forego consuming electricity when it would rather save the cost

of consuming power than consume power. If the right price signal is given for this decision—and that, I submit, is LMP-minus-G, then there is no need for the benefits test.

DR occurs precisely when it's efficient to forego consumption. In contrast, under the Net Benefits test we would procure DR not when it is efficient for the consumer to stop consuming but when price suppression effect exceeds that cost.

We thus face the prospect of paying the DR resource more than is necessary to induce the resource to stop consuming in order to achieve the net benefits for load. This way of thinking is directly analogous to the trading strategies the Commission found potentially to constitute market manipulation in Amaranth and ETP.

There the Commission was deeply troubled by traders allegedly trading against their economic interests in one market to benefit positions in other markets. So, too, here.

Load would overpay for DR inducing conservation, or in many cases for industrial consumers the ability to [28] turn on dirty, behind-the-meter diesel generators that they own, for the purpose of broadly reducing wholesale prices for retail consumers. When a more efficient decision would be to continue consumption.

This is not simply an abstract thought. In reports sponsored by the New England Load Interests in 2007 and 2009, Synapse Energy Economics described a

cost/benefit analysis for procuring DR that expressly incorporates something called "DRIPE," or "Demand Response Induced Price Effect."

In a nutshell, they expressly contemplate deciding to procure a DR not because it is an economic procurement decision on a stand-alone basis, but because of the purported benefits of suppressing prices in the energy markets.

This is really the mirror image of a generator withholding. On a standalone basis, a generator would be acting economically; but if the resulting reduction in supply drives up the clearing price, then that loss may be more than offset by the increased revenue earned by the rest of its portfolio.

It would hardly be a valid defense to a charge of withholding to point to the profits earned by the rest of the supplier's portfolio, but that is really what we're doing under the entire Net Benefits test, and asking FERC [29] now to bless this very process that would not be permitted if it were done on the supplier side.

The Net Benefits test is really the equivalent to DRIPE. Whether to procure a DR is, in effect, distorted by the potential for load, reaping the short-term benefits of energy market suppression. Both metrics are inefficient and unlawful.

Second, I would like to briefly address Professor Kahn's recent affidavit. This filing is very close in an important way to Dr. Shanker's affidavit for NFCA in this proceeding. As Dr. Shanker explained, DR

should be conceptualized as a call option. The consumer effectively purchases the option from the LSE to call electricity at a particular strike price. That is, the retail rate the consumer pays to the LSE.

Professor Kahn agrees with viewing DR as a call option, but he fails to follow through on the logic of that view, which is that the consumer that offers DR must pay the strike price, the retail rate, in order to provide DR to the market.

Professor Kahn and Net Benefits supporters propose to solve half the problem. They would have the Commission supplement the retail price signal, but would omit the necessary component of reflecting in that price signal the need for the DR provider to pay the strike price [30] for its call options. That is, again, the retail rate.

This position advocates intentionally reaching the wrong result, over-compensating DR and then hoping that each state commission will take counteracting measures to cure the mistake.

The better course, and the only course consistent with Just and Reasonable Rate outcomes, is for the Commission to create the correct price signal at the outset. Thank you.

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MR. HUNTER: All right. Thank you, and finally we've got Dr. Roy Shanker, a consultant for the PJM Power Providers Group.

DR. SHANKER: Thank you, David.

MR. HUNTER: You're welcome.

DR. SHANKER: I'd like to thank staff and the Commissioners for having me today. I've been asked by the PJM power providers to comment on the two issues for today that the Commission identified, Net Benefits and Cost Allocations, particularly Net Benefits in this panel. As usual, these comments are my own and do not necessarily represent the opinions or positions of the people sponsoring me today.

I have to say that I find the two topics of today's technical session a bit perplexing, as they appear to assume away much of the substance of the Commission's initial inquiry and seem to have been based on the pursuit and the selection of what I see as the wrong answer.

If the Commission adopts the appropriate nondiscriminatory pricing for Demand Response, and payment of LMP minus the retail rate in the context of customers that face a fixed retail rate, then there is no need for a Net Benefits test.

[61]

The LSE pays the customer the difference between the LMP and the customer's retail rate, and the customer receives the difference between LMP and what they would have paid under their rate, which is their net benefit. Therefore, there's no need for any additional test or calculation.

Similarly, under such compensation, there is no need for any subjective cost allocation. The financial consequences all fall to both the LSE and the conserving customer. There are no transfers from other parties and thus no other costs to allocate.

Considering these two facts from my perspective, the entire discussion today is based on proposed solutions that fall out of the wrong answer to the initial question. Further, this question or this discussion regarding the nature of the proposed Net Benefits criteria is troubling in and of itself, as it explicitly incorporates consideration of portfolio effects caused by the reduced demand on all load payments, versus the economic decision-making of individual market participants pursuing their own legitimate business purposes.

This appears to coordinate the very type of market behavior that would be totally unacceptable if engaged in by suppliers. The best way to see this is to indulge in a slightly rhetorical analogy.

[62]

Assume there was a meeting of an electric supplier group representing 150 megawatts of capacity in PJM. They notice that the independent market monitor has commented that a shift of two and a half percent of demand, approximately 3750 megawatts in the PJM capacity auction, changes payments to suppliers by approximately $2 billion.

Assuming the same impact for a reduction in supply, they decide to identify the 3750 megawatts of existing generation that has the lowest net operating margins. They discover that the worse-performing 3750 only nets $1,000 a megawatt year, or $3,750,000. They conclude that this is a wonderful opportunity to improve the economics of the group by $2 billion if they pay the 3750 to retire, physically withhold the generation.

However, immediately there are problems. The owners of the 3750 want more than $1,000 per megawatt year, and the remaining suppliers are arguing among themselves how to divide up the $2 billion. So they decide to petition the Commission for guidance on the best criteria to reduce supply, while maintaining an efficient, reliable generation fleet.

They also ask for guidance on how to allocate the increased revenues among suppliers. My suspicion is rather than holding a technical conference, most discussions with the Commission might instead address whether or not the [63] suppliers could negotiate for

adjoining jail cells while they continue their discussions.

(Laughter.)

DR. SHANKER: Yet facetious as this sounds, upon consideration it's not any different from what's being discussed today. Collectively, parties are negotiating on payments in excess of what is economically efficient to drive down demand and price, and justifying it based on portfolio effects to be received by buyers collectively, via the reduced market price.

They're asking for guidance on the optimal decision-making and structure for this price-suppressing portfolio effect, as well as guidance on the distribution of the costs associated with the otherwise uneconomic decisions.

This is exactly the type of behavior that is continually monitored for and stopped when observed in supplier actions, and based on Commission precedent and capacity markets and elsewhere as mentioned by Joel earlier, this is also frowned upon in terms of purchasers' behavior. These types of actions contain all the elements of the exercise of market power by buyers.

With the above in mind, my short responses to the Commission's questions regarding Net Benefits are first, should the Commission adopt the Net Benefits test. I [64] believe that from the above, it's clear that beyond getting the price right, LMP minus the retail rate, and actual LMP if at all possible for the price to

be paid directly, the Commission should not adopt any further benefits test.

This in turn answers the second question regarding how to define benefits. That is, that the right benefits are revealed by the right price. The payment in this case for a fixed price retail customer by the LSE of LMP minus the retail rate.

Similarly, there's no need to consider other costs of demand responders, as they will make their own decisions regarding participation, based on the right pricing. In turn, there's no problem with identifying the beneficiaries as the participants in any approved program that verify their actual reduction in demand.

The fifth question, whether a common Net Benefits methodology should be adopted is also clear. The common generic compensation should be the LMP minus the retail rate for the customers that fall into the fixed payment class.

Finally, there is no need to address a benefits special. The full benefit, when manifest, is a payment of the right price, should always be available to the demand responder. It is only in the presence of discriminatory subsidies that creates the potential negative benefits by actually increasing total costs for customers, when [65] subsidies exceed the aggregate price reductions. This concludes my remarks.

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DR. SHANKER: Yes. I think there's a couple of things. First, I would probably agree with almost everything Audrey said, if the customer is paying LMP to begin with. But that's not what's happening. We have an enormous amount of load that is seeing a fixed price, and this comes back now is where we close the loop with what Don said, and where I strongly disagree, is that you can look at the fixed price retail arrangement as the LSE having sold a bunch of calls in the retail market.

You can look at the payment of LMP as opposed to LMP minus the strike price as overpaying or overcompensating a group of parties that hold the call position, by the amount of the call position in excess of what the market price is, in order to suppress price in another market, in the wholesale market, where those same parties are very long or I'm sorry, are very net short, have large net short positions.

[70]

If you read, Joel referred to the Amarenth and the ETP decisions, what I just described, manipulating price by overcompensation in one market where they have sold calls, to suppress price in another market where they are, have large short positions, reads like the introductions of the Enforcement staff to the Show Cause orders in those two cases.

And so it's not something that should be ignored. It should be a fundamental issue as to the decision-

making of the Commission, as to whether or not you are going to overcompensate in one market to suppress prices elsewhere, and the portfolio effect of that suppression seems to be what everybody is talking about.

If there were no overcompensation, there wouldn't be any need for all these concerns about Net Benefits test and possibly losing money. It's inherent in what's going on. That's why we're discussing this.

MR. HUNTER: Just to clarify, when you talk about the portfolio effect, you're talking about the overall effect on—

DR. SHANKER: The over—yes. The Net Benefits calculations all seem to be predicated on how much does the rest of load save by the price dropping. That's what I meant by portfolio, as opposed to, you know, marginal clearing price. That was not—those two did get a little [71] jumbled in some of the comments.

When I said "portfolio," I'm talking about the third party beneficiaries of a suppressed price, or in this case maybe the same party by doing it, by overpaying for buying out their call positions in the retail markets.

MR. HUNTER: And just for those of us who aren't finance majors, explain again the argument that it's effectively a call option?

DR. SHANKER: Okay. We're talking—as I said, I agree on an LMP customer, someone who pays

LMP at retail or something close to LMP. We're fine, because LMP minus retail rate turns out to be zero, and they just see the LMP. Then I agree with everything Audrey said. But let's say from PEPCO, from PDS I would get an $100 a megawatt hour price.

I have the right to execute that. That's me and my home, at when LMP could be $200 or $300. So PEPCO, as the LSE, has to go out and buy from the market, let's say at $300, but I only—I have the call on them at 100. So they're going to lose $200, okay. What we're talking about in the correct compensation is essentially them being held neutral and giving me $200, okay.

They're going to lose $200 one way or the other. So they either buy it out of the market and they convince me not to consume. So they give me $200, which what they would [72] have paid. I would have given them 100; they would have given another 200 to PJM and bought the $300 energy.

If alternatively they gave me 200 and I don't consume, everybody's in the exact same position. But let's say they give me $300, and you say well, why would they do that? That's what's being discussed here today, is giving me 300 instead of 200. We start to look and they say well, if I give enough of you 300, I know it's too much money. That's why you're concerned with overpayment, and in driving the net benefit negative.

But if I give enough of you $300, particularly when prices are very high, aggregate demand will drop from 300 to say 200, and the other 100,000 megawatts of load in PJM all say it's $100. So it was worth it. Part of that other 100,000 might have been positions held by PES. So we're concerned directly when people sit down and say a lot of us are short in the wholesale market.

If we overpay people in retail to drive their consumption down, it's going to give us a net benefit on the wholesale side of reducing prices. Now it sounds good in general for consumers, but really the transfer here is going through the LSE. It may go to the consumer; it may not. Mr. Ott mentioned that he didn't know who's hedged. If everybody were hedged and that happened, the entire benefit of this would go to the LSEs. None would go to the retail [73] customer.

MR. HUNTER: Any of you had it up there? I may have called you out.

MR. OTT: Yes. I was going to try to help, but I think—let me—the key is that comparability. In other words, absolutely every megawatts injected or every megawatt not consumed should be paid LMP at the wholesale level. We aren't debating though.

When I pay the generator LMP to bring that energy in, they had to buy a forward fuel contract or they had to buy something to give me the energy. Nobody's discussing—in other words, their net profit, if you will, has to do with what they had to purchase on a

forward basis, whether it be fuel or energy, and then sell it in that wholesale.

On the retail, I mean on the demand side, if somebody bought a forward contract to pursue them out on the exchange to consume, and they brought it into our market and then they decided hey, I'm not going to buy from that market because effectively, you know, I could make some money here. So they essentially don't buy, take that money and they made money on their forward contract, okay.

Basically implicit in this, because we have the retail side of this, the right to consume does—it not priced at zero. They had—somebody has to pay money, and [74] that's the fixed retail rate. If you ignore the fixed retail rate, it's like ignoring, you know, the generators, you know, fundamental cost. I think that's what they're trying to say. I'm trying to put it in different words. But that's effectively the differential, I think, that Roy was trying to explain and I was trying to come from a different point of view.

MR. HUNTER: All right, thanks. Joel, you had yours up?

MR. NEWTON: Thank you. I guess coming from a slightly different way, and just focusing on the call option that we've been discussing, when we look at this, you know, it was very interesting listening to Don's earlier remarks, because he agreed, and as did Professor Kahn, that we are dealing with the call option, and the question then is who is it between?

I think as Andy was just saying, the call option is really between the LSE and the consumer. What's being proposed then by Professor Kahn then is that the consumer then has the right to sell its option, without having to do anything about the strike price that it agreed to enter into to the ISOs.

That's really what his theory, the entire theory is, as to why they should be able to be paid the entire LMP and ignore the LSE all together. What we're saying is that [75] actually the LSE is very important here, that the agreement by the consumer was to pay the strike price, and that is the retail rate to the LSE.

The Commission is getting into a real close area with retail ratemaking as we go through this entire process. For the Commission then to say "ignore the LSE payment," which really is the realm of state commissions, it's almost as though you're just hoping that the state commissions will go out and fix it.

The state commissions can do that. They can go out and individually say we're going to handle this differently. But the proper thing to do now is to get the price right at the outset. Now in Amarenth, the Commission Enforcement staff noted the fact that, you know, the job of the Commission is to police the behavior of markets, and its interest isn't simply in one side of the market, the consumer, but also the seller side.

My real concern as we're going through this entire process and listening to many of the different panelists

is that the goal here seems to be to focus on the one side, with the Net Benefits test being the consumer side. We need to make sure that this market works, and I think that what a lot of panelists are now saying is that we need to look at the retail rate as part of the overall product that's being sold and purchased.

[76]

MR. HUNTER: Okay, thanks. Before I get to Audrey and Don, since we brought up retail rates, John's got his card up, something to say.

MR. KEENE: Yes. I just think I have two points in response to this concept of the call option and being required to buy that ahead of time. I think first of all, I think it's inherent in the regulatory compact that already exists with the local utility, has an obligation to serve.

So those end use customers already have that call option, and they were given it by the regulatory compact. They already own it and own it for free. They should not have to pay anything further to have it to call upon. So that's my first point.

The second point is this whole debate is really circling around the compensation issue rather than that benefits test. But you know, as we addressed in our initial comments, whether you have to buy the LMP ahead of time or whether you only pay LMP minus G, that's theoretically the efficient price. That's right.

But it's not enough to overcome the well-documented market barriers that are known to exist, whether they be technological, political and so forth. So if we're going to overcome those barriers and get a level of Demand Response that is closer to the optimum that would exist in a truly price-responsive market at all levels, then we need to [77] pay the full LMP, and we believe that's the appropriate price to pay. Thank you.

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MR. NEWTON: Thank you. I think that, and as Don was just talking about, there are other markets that do need to be looked at, and probably the capacity market is an important one. Right now, we have demand really participating in two different ways.

[88]

One, it can participate directly, and is a competing resource. Secondly, with a lot of the energy efficiency programs, it simply takes off from ICR. Whether it competes directly or as a subtraction to the total installed capacity requirement is really meaningless from the total amount of capacity that the consumer is purchasing. It simply is who is it purchasing it from.

An interesting question I think that we are getting to is a comparability question. What we're getting at here is are we really looking at comparable products to start with, or should, for example, the DR participate

more through—be reflected in the ICR, but participate more through the market mechanism, because of what its function is and how it seeks to participate.

I say that because we're looking at, and I believe Bob said this in his earlier remarks, at a point where we're having the pricing change in a way that may be unintended, if DR is receiving more and more money through the markets, which you know, I'm not saying that it shouldn't in any way. We of course state what we believe should be that payment, it will need less money through the capacity market in order to make up its entire price.

And indeed, they may be priced at zero at that point because if it's being paid a full LMP; it may be in the money at the very beginning. The other place where I'm [89] somewhat troubled from a legal standpoint, and I've researched and I don't have an answer, is where we are with the Energy Connect case.

At this point, the Commission has stated that the product that is not being sold is really—it's a service, that DR is essentially a service and not a product. Yet when we're in the capacity market, we're talking about products. So we seem to be mixing and matching services and products in ways that I don't believe the Commission has fully taken into account at this point.

Finally, I think that as we're going into the various markets, it is important for us to look at the comparability issue in all different ways, and whether or not

the payment structure is appropriate in one market versus the other should be looked at on a comparable basis. Thank you.

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DR. SHANKER: A couple of things. You're getting down to the Net Benefits mechanics, assuming you go that way. It's not clear in the other two markets. I think it is transparent in PJM that you would, all other things equal, you would increase capacity prices, because energy and ancillary service margins would drop, and they're on a rolling historic average.

So they would straightforward—you would see, at least in the reference price for the auctions, you would see an increase in the capacity prices. So if you really want to do this kind of benefit, then you really should take a look through those energy savings. They go in one pocket and then they're going to start coming out on the capacity [95] side in increased capacity prices.

And there still seems to be some confusion about this notion of the option, and I'd like to clarify that if I can, and maybe you're probably aware of other confusion. It's not the purchase of the option that we're saying is free or not free. I agree with Don's position, but that's not what the point is.

It's associated with the option is a strike price for the energy, and the retail customer has locked in, whether it was given to him or they paid for it. In

that option, he's locked in an execution price. We're saying, and I think Dr. Hogan has the comment more generally; I say it in one line, is you've got to buy it before you can sell it.

So in this context, to make good on the option, to be able to possess the product that then goes back into the market, whether you paid for the option or not is irrelevant. But you do have to pay the strike price. That is the retail rate. So that part is inherent in the calculation, and that is why is Bob is saying I've got to worry about the G, you know.

The G is what's missing. The G is the missing money. It is the strike price. If it doesn't get paid, he has to find somebody else to foot the bill. And that's, we're trying to separate that from the cost of the option [96] itself. We're trying to talk about the strike price of the option.

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MR. PECHMAN: Roy, I have a question for you. You've talked about the interrelationship between the DR compensation and the capacity prices. Have you done any empirical analysis to provide bounds on what you expect the impact would be on the capacity prices, or is this just—this is the direction you expect it to move in?

DR. SHANKER: No. When you're—the answer is any empirical work—to clarify what Bob is saying,

there are more things going on. But if, and it's not—I mean somehow the notion of looking for the right price that might be a little lower than somebody else's view of the right price, is being translated into DR is awful and you shouldn't do it.

That's not what's going on here. I mean I'd love to see higher penetrations of real Demand Response. I'd prefer to see it formed as price responsive demand systems like Audrey is talking about are wonderful. I represent people who are doing things like that.

But the issue is you want to get the price right. Part of the impact here will be in doing all these things, it will change the average prices. In the energy markets, we'll probably—in the capacity markets, we will see the [105] unit price of capacity go up. We may need less capacity. That may be a benefit on the other side. It has to get netted out.

When you're doing something, when you're sitting in the role of saying I want to change the price artificially, at least from my view artificially, you've got to track these things. If you want to say just put all the customers on LMP and pass it through and they decide, okay.

So they pay LMP for their retail rate. They don't have a call other than at LMP. Then you can close your eyes to all this and not worry about it. Or if you're going to still have fixed rate customers, you've got to compensate for that call option we're talking

about. I mean but it's not saying not to do it; it's just saying to do the right amount of it.

It will, and it will—it may go up. The unit price absolutely, I think, goes up in the PJM capacity markets. We probably do have, we do have information on that, I guess. You know, I suppose we could get information on that.

But the aggregate amount, I don't know that you would know whether or not it would, you know, could encourage more penetration by DR as a capacity resource in emergency programs or the capacity programs, in which case the total price might go down. The total amount might go [106] down, but the price might go up.

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DR. SHANKER: Again, it seems that we are getting [115] off course in terms of the discussion of the benefits of DR and the price. The benefits are undeniable. I have a client that I've worked with that round numbers, so I'll sort of keep them unidentified, 130 megawatts of load. It's a large industrial client.

They can shift, they have a preliminary or pre-processed good that they then finish. They can store that pre-processed good. So they have—part of their operations, maybe 100 megawatts, is creating an intermediate good in the manufacturing process that can go into storage, and 30 is finishing it.

So when prices are high enough, they back off their pre-processing and they, one of the projects I did with them, we sat down and figured out when they should build storage for this intermediate product.

They'll run a third shift and they'll take labor and they'll go over and they'll put that third shift on, when prices are high enough, and develop that intermediate good in the middle of the night. They'll buy electricity then, and then they'll only run during the day the 30 megawatts, and actually they'll run the 30 megawatts all the way through, okay.

Now they do that and will make that decision, whether it's LMP or whether it's LMP minus the retail rate, and in fact they've experienced both, and their behavior [116] changes. So it's not like this goes away and suddenly nobody's thinking about storage or shifting. It's the question of how much should they be doing it. What's the right amount? What's the resource allocation?

It's not like if you don't give people LMP, they won't behave properly. They're going and doing it. They're doing it, and I think you're going to hear from a lot of people and what you heard in the comments was it's not a question of denying the process; it's the question of getting the quantity right.

If you're overcompensating people, understand where those subsidies go. Audrey's business is a lot tougher if it's LMP minus G than if it's LMP, because part of those subsidies will help her business. It's

nothing against her business model, but that's the reality.

There will be more consumption of these types of resources if we pay LMP versus LMP minus G. The question I thought we were dealing with is is that good? Just to have more of it doesn't make it good. It's to have the right amount is what's good, and that's—somehow we're changing more and saying more is good just automatically, and it's just not true.

I mean we want to get the price right to get the level right. I mean why not pay two LMPs? I bet you you will get even more, and we can have a Net Benefits test that [117] will show you paying two LMP will actually get you more Demand Response in the peak hours, and it will show a positive benefit.

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MR. QUINN: Bob, how would you do that? Would you do that on a kind of an after the fact basis by determining the number of hours or the price threshold, to then apply for the next X period of time and how would you define what the X, the next X period of time would be?

DR. ETHIER: Well, the nice thing about if you adopt a Net Benefits test that ISO advocates for, is that you don't need to do a test. If you get the payment rate right, there's no need to do a test because it just falls out.

MR. QUINN: By payment right, you mean LMP minus some retail rate?

DR. ETHIER: Yes.

MR. QUINN: What if we don't do that?

(Laughter.)

DR. ETHIER: Okay, then what's your question?

(Laughter.)

MR. GOLDENBERG: Oh well, I think the question is how do you do your test if you don't pay LMP minus G, but paid full LMP?

DR. ETHIER: Well, the test that I would advocate, you would—basically you would not pay in any hours the full LMP, because it wouldn't pass the test.

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AFTERNOON SESSION

(1:05 p.m.)

MR. HUNTER: Okay, so this afternoon's panel is on Cost Allocation. The same format as this morning. We will have brief, five minute, remarks from the ten panelists, this time, and then we will open it up for discussion.

First let me introduce the panel. We've got Commissioner Paul Centolella from the PUC of Ohio. Dr. William Hogan, Professor at Harvard University.

Sonny Popowsky, Consumer Advocate from the State of Pennsylvania. Michael Robinson, Senior Manager, Market Development, from Midwest ISO. Carl Silsbee, here from California, Manager of Resource Policy for SoCal Edison. Tim Brennan, Director of Wholesale Markets for National Grid. Kenneth Schisler, Senior Director of Regulatory Affairs for EnterNOC. Angela Beehler, Senior Director of Energy Regulation/Legislation for Wal-Mart. Megan Wisersky from Madison Gas & Electric, representing the Midwest TDUs. And Jay Brew, counsel for the Steel Manufacturers Association. Thank you all for coming.

Anything from the Commissioners before we started?

(No response.)

MR. HUNTER: Okay. With that, we will start off [140] with Commissioner Centolella.

OHIO COMMISSIONER CENTOLELLA: Thank you for this opportunity to comment on the Commission's proposal for Demand Response compensation and related cost allocation issues.

The ability of Demand to respond to energy prices is an essential characteristic of an efficient, competitive market. Demand Response provides significant economic and reliability benefits. It can avoid the need to rely on more expensive resources, mitigate market power, and improve power system reliability.

The Commission proposed requiring RTOs to pay economic Demand Response program participants in all hours the energy market price, or full LMP. Where the Demand Response program participant is not reselling already-purchased energy, paying LMP instead of LMP less the avoided generation portion of their retail rate, will compensate the participant by an amount that substantially exceeds the marginal cost of energy and the price being paid to generators.

The extent to which each participant's total compensation exceeds the energy market price depends on their retail rate, and therefore will vary widely in ways that are not directly related to any Demand Response policy objectives.

[141]

The Ohio Commission has not opposed RTO Demand Response programs to provide it additional limited temporary incentives designed to support the initial development of Demand Response. However, RTO programs should seek to provide an efficient level of total compensation to program participants. Any additional incentives should be reasonably required to address market imperfections or achieve other carefully defined policy objectives. Requiring all RTOs to pay full LMP does not meet this test.

The Net Benefits test reflects a recognition that paying full LMP may over-compensate Demand Response and increase cost to consumers. It is a complicated approach. The formula approach we heard

this morning, based upon maximizing consumer welfare, would fundamentally change the objective function in RTO dispatch algorithms.

Moreover, while Demand Reductions could lower LMP if the slope of the supply curve is sufficiently steep, this will not uniformly occur above any certain price point. And any reduction in energy market prices may simply increase capacity market prices, making the overall calculation of Net Benefits complex.

The Ohio Commission is concerned that FERC's exclusive focus in this docket on the payment of LMP for Demand Response resources could have the unintended consequence of retarding the development of price-responsive [142] Demand.

While significant, RTO Demand Response Programs reach a small percentage of consumers. Advanced metering and dynamic retail rates would give many more consumers control over their electric costs. Electricity markets would increasingly resemble competitive markets in other sectors of the economy where consumers simply see and respond to prices.

The factual premise put forth by proponents of the full LMP approach is one that is rapidly changing. Millions of advanced meters have been and are being installed. Initial dynamic pricing experiments have shown promising results, and utilities in collaboration with the U.S. Department of Energy and State Commissions are undertaking carefully structured experi-

ments to identify the best combinations of dynamic retail rates, information, and enabling technology for residential and small consumer customers.

The FERC's national assessment of Demand Response potential examines the potential for dynamic retail pricing and found that the largest gains in Demand Response impacts can be made through pricing programs.

The cost of reductions in peak demand to residential consumers also appears to be substantially lower than the costs of curtailments to industrial energy users [143] and commercial consumers who provide the majority of Demand Response in RTO programs.

Moreover, when implemented in a SmartGrid, Demand Response can provide a broader range of economic and distribution system benefits not available from RTO Demand Response programs.

This Commission has recognized that appropriate coordination of—the lack of appropriate coordination of wholesale and retail markets can operate as a barrier to Demand Response participation. However, the Commission has not yet, one, removed the resource adequacy requirements that force price-responsive loads to carry capacity for demand that would not be present at higher prices; two, ensured nondiscriminatory treatment of price-responsive demand; or three, completed the implementation of scarcity pricing under Order 719.

In addition to diverting attention from these key issues, the payment of full LMP could retard the development of price-responsive demand in two ways:

First, the purchase of Demand Response resources at full LMP effectively discriminates in favor of RTO program participants over consumers responding to retail prices, and will displace price-responsive demand that could have curtailed for less than the total incentive received by RTO program participants.

[144]

And second, the additional incentives for Demand Response resources will increase RTO costs that flow back to utilities and consumers, leaving fewer resources to make the necessary investments in metering and enabling technologies.

The costs of DR programs should be allocated to those who benefit, with allocations dependent upon the objectives and nature of the incentives provided.

Where an RTO uses limited incentives to support the development of Demand Response in a zone or region, the cost of these incentives may be allocated across the zone or region to reflect the shared market benefit.

Despite the previous difficulties mentioned, where there may be some legitimate basis for tracking Net Benefits, such benefits could also be used as a basis for cost allocation. If the Commission directs RTOs to pay full LMP, it needs to clearly state its objective and

should adopt cost allocations that minimize distortion in rates. There may not be a single standard approach for all RTOs in this case.

In conclusion, to focus narrowly on wholesale prices for Demand Response while ignoring the retail price signals seen by actual consumers will ensure an inefficient outcome. It is an outcome that states may not be in a position to correct, as we do not regulate the rates of competitive LSEs.

[145]

Efficient markets require coordination between FERC and State Commissions. Such coordination can support the development of the next, more efficient generation of Demand Response based on a broad implementation of price-responsive demand.

Thank you.

MR. HUNTER: Thanks, Commissioner. Next up we've got Dr. Hogan.

PROFESSOR HOGAN: Thank you very much for having me here today. I've prepared written comments, which I have provided, so I am not going to repeat everything, but I wanted to emphasize a few questions, several questions, that are in those comments.

Why are we here?

Why is this subject so confusing?

Why are retail rates relevant?

How can we match ends and means?

Do we need a Net Benefits test?

How should we allocate costs?

And where should we go from here?

Why are we here? Well, I think that's pretty well understood, and I've described it further, but it's to see how Demand Response fits into the larger market design. It's an important test, and we want to make sure it is compatible with the rest of the system. And I submit that [146] the current proposal is not compatible with the rest of the system, so it is important to try to get this straight.

Why is this subject to confusing? This is such an important point that I am going to read, literally, what I submitted: In his NOPR reply comments, Alfred Kahn refers to, quote, "to the proposition, in principle indisputable, that demand response is in all essential respects economically equivalent to supply response; and that economic efficiency requires, as the NOPR recognizes, that it should be rewarded with the same LMP that clears the market. Since DR is actually and not merely metaphorically equivalent to supply response, economic efficiency requires that it be regarded and rewarded equivalently as a resource proffered to system operators and be treated equivalently to generation in competitive power markets." End quote. This is an important premise, critical to the Commission's proposal.

Were it true, the present proceeding would not be necessary. But it is not true. The megawatt of Demand Response is a powerful metaphor, but a megawatt negawatt is not equivalent to a megawatt. The two have features in common, but they are not the same physically or economically. Useful application of the "Negawatt" Idea requires care in the analysis.

Amory Lovins, originator of the Negawatt Idea, [147] has been quoted as saying that he takes economics, quote, "seriously, not literally," end quote. This is good advice, and it would apply as well to the design of compensation rules for providing Demand Response through providing Negawatts.

Taking Negawatts and Demand Response seriously is good policy. Building a Demand Response policy on a literal application of the megawatt metaphor produces contradictions and conundrums.

The fundamental contradictions and conundrums center on the difference between reselling something that you have purchased, and selling something that you would have purchased without actually purchasing it. If the something is a kilowatt hour of electricity, the two conditions are physically identical in providing Negawatts, but they are fundamentally different in economic terms.

The former kind of Demand Response is easy to accommodate in prices the Commission has proposed, and the latter requires more care in the design of the compensation mechanism.

Why are retail rates relevant? There are many who have argued that we shouldn't look at the retail rates, and in effect we should be drawing a veil of ignorance over the retail market and just look at the wholesale market and we don't have to worry about the rest of it, let's just have [148] efficient pricing in the wholesale market.

But I think the implication of that argument is exactly the opposite of what has been suggested. Because if we drew that veil of ignorance over the retail tariff and we just looked at the wholesale market, we would say well what's the right thing to do?

Well, real-time pricing is the right thing to do. And charging the LMP for the megawatt hours they consume, and you're done. You don't need an additional Demand Response program, and it would be inappropriate to do so. But the problem is, we know that in the retail rate side the demand that's being represented is not an accurate representation of the demand. It's not the way the real cost incurred are incurred in the system. And so the whole motivation for having special Demand Response programs is precisely because of the retail rate structure.

And pretending that you can ignore that is just backwards thinking. And if you did ignore it, you would get the opposite answer that everybody seems to suggest. So I am in favor of efficient Demand Response programs. I'm not in favor of doing nothing. But the notion that you can ignore the retail rate I

think is a perverse twist in the logic and it doesn't make any sense. We have to look through to that.

How can we match ends and means? Well, I'm going [149] to not summarize that here because I don't have enough time, but just to say that this is where I discuss, among other things, the point about reducing the price to consumers is not an appropriate benefit for FERC to be considering.

From the perspective of generators, this is a cost. From the perspective of loads, it is a benefit. But from the perspective of economic efficiency and welfare maximization, the aggregate effect is a wash and there is no net benefit.

To the extent that the Commission's proposal depends on the benefits of price reduction, the policy arguments amounts to no less than an application of regulatory authority to enforce a buyers' cartel. The Commission has been vigilant and aggressive in preventing buyers and sellers from engaging in market manipulation to influence prices, and it would be fundamentally inconsistent for the Commission to design Demand Response compensation policies in order to coordinate and enforce such price manipulation.

So I think that an efficient set of Demand Response policies would be appropriate, but that would not count as benefits by changes in the prices to the final consumers.

There are many other points that are in the written testimony. There is a simple summary of the basic

[150] line of the argument, which is, I agree with him [indicating Commissioner Centolella]—

(Laughter.)

PROFESSOR HOGAN: So I am going to save myself some time, except to emphasize one point, which is: I agree with him, but to say how important it is. It says: The Commission's work under Order 719 on scarcity pricing is important and should be a high priority in conjunction with the promotion of the SmartGrid.

And where should we go from here? We should go to that meeting.

Thank you.

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[154]

MR. HUNTER: You're welcome. Thank you. All right, thanks. Next we have Michael Robinson from Midwest ISO.

MR. ROBINSON: Thank you. Thank you, Commission staff, and Commissioners, for this opportunity to speak on [155] this topic.

At Midwest ISO we certainly are involved and doing our best to actively engage Demand Response in our markets. We have over 10,000 megawatts of Demand Response in our markets. And to my understanding, we are the only RTO in the States that has a true Demand Response resource providing regulation

service. Not a behind-the-meter generator, but Demand Response.

We have an active stakeholder process that is engaged in removing barriers to participation. We come under the philosophy of we're conducting these markets for our various products and services. How do we establish a level playing field? How do we make these resources comparable—provide comparable treatment across generation and Demand resources.

So you asked a few questions here today. One is: Is the Cost Allocation a function of the level of compensation? What's the appropriate Cost Allocation method? And then finally, should we use a net—what's the role of a Net Benefits test in the role of Cost Allocation?

Let me address the last one first. A couple of speakers this morning already fleshed this out, but clearly if you get the markets right in terms of competitive markets and efficient pricing, you don't need a Net Benefits test. Okay? So if the counterfactual to that is when would you [156] need a Net Benefits test, would be—or the contrapositive would be, you would need a Net Benefits test when the markets don't work.

Now a couple of different reasons where markets wouldn't work. Dr. Hogan talks about one of them in his paper, when you have inefficient pricing. To mitigate the harm to market participants, you may want

to have a situation where you do have particular Cost Allocation.

The other one where markets don't work is where I can make the case that for some reason there is a positive externality—there's market failure, and there's a positive externality associated with this particular resource. In that particular case, then that may be appropriate for Cost Allocation.

Having said that, though, does the Cost Allocation depend upon the level of compensation? It truly does. If there is inefficient pricing, or positive externalities, that will suggest a particular Cost Allocation scheme.

If you get the prices right, then I think the Cost Allocation flows directly. What we proposed, and this was involved significantly through the stakeholder process was, we would—and Andy Ott talked about this this morning, where from the wholesale markets administrator's point of view, the value of the load drop is truly LMP.

[157]

So pay the DR, provide LMP, but appropriately charge the load-serving entity LMP. Okay, and then recognizing, look behind the curtain, recognizing that there's some avoided retail revenues that have to be accounted for.

I can think of at least five or six different reasons why the Cost Allocation should go to the appropriate LSE. One is, examine the counterfactual. Essen-

tially if the load didn't drop off, the load-serving entity would have to serve that load would be paying LMP.

The second one is, the argument then is, well, you're going to have to somehow reconstitute load to settle it out appropriately, to solve the "missing money" problem. So there's this funny concept called "reconstitution of load." Whereas in the world where there's just generator and load, you'd sort of directly meter what they inject and what they withdraw.

Yes, it's true it's a little bit of an odd concept, reconstitution, but it's no different from calculating a CBO, which may not be reconstituted but it's certainly constituted. So in that sense it's sort of comparable to what we do with trying to measure the load drop from a Demand Response asset.

The third reason I guess in the interest of time I won't talk about too much. I think Dr. Shanker talked [158] about it this morning, the sense of if you have significant baseload generation that comes in, that's going to depress LMPs and provide net benefits to the market.

And so the whole issue of do we want to have uplifts that distort prices, we're trying to avoid that.

The next reason is, if you think about how retail rates are structured under a fixed tariff, the design is hopefully to set up a rate so that on average costs are recovered. The result of that, though is that during the high peak hours the retail utility is actually losing

money and recovers additional monies in the off-peak hours and the low-cost hours.

So if we don't charge the LSE, then it's possible that the LSE will incur windfall profits, and so that has to be addressed.

Number five is the call-option argument. That's been well discussed this morning.

Then the last one is, no one has really talked about this one, but typically load-serving entities procure most of their obligation in the Day-Ahead. So if you don't charge the LSE for this particular load drop in terms of reconstituting load, then essentially you're paying for that load drop twice. You're paying the third-party provider, the DR provider, and when the LSE sells it back in real-time he's getting compensated as well. So you're paying for the [159] same megawatts twice. And so that's the last rationale for providing—charging the LSE.

We recognize that if you look behind the curtain that there are avoided retail revenues that the LSE in this particular regime is not indifferent. And so as a service to the LSEs and to the retail—the relevant electric retail regulatory authorities, we offered to back out from the LMP the marginal foregone retail rates that the end-use consumers were avoiding.

We provide that as a service. If this Commission decides that the appropriate compensation is LMP, then I'm sure that the relevant electric retail regula-

tory authority will make that case and flow those credits back to the LSE from the third-party provider.

Thank you for giving me this opportunity to speak.

MR. HUNTER: Thank you. Next up we've got Carl Silsbee from SoCal Edison.

MR. SILSBEE: Thank you. Good afternoon Commissioners. Thank you for the opportunity to participate here today.

My company, Southern California Edison, has actively pursued a wide variety of retail Demand Response programs for over 30 years. Today we have about 1700 megawatts of proven capacity from our Demand Response [160] programs, which represents about 7 percent of our service area off-peak demand.

Our largest single program is an air conditioning cycling program for residential and small business consumers. There's over 300,000 participants on that program, and it supplies about half our total Demand Response capacity.

We are in the process of transitioning that program from a purely reliability-based program to a program that will include a price responsive trigger and, as such, will bid into wholesale markets managed by the California Independent System Operator.

The certainty of our Demand Response program capacity is assured through a combination of performance incentives, performance penalties, and hard-

ware control, depending on the nature of the specific program.

The capacity value assigned to these programs by the California Public Utilities Commission is periodically adjusted to reflect actual historic experience. Forward capacity obligations are managed by the California Public Utilities Commission in California, not through the California Independent System Operator.

We rely on our Demand Response programs both to maintain system reliability, and to give participating customers better options to manage their electricity [161] consumption and their retail bills.

Over the last several years, the California ISO has managed a stakeholder initiative to create a wholesale market process called Proxy Demand Resource, or PDR. This is a program, not a specific product, and we see it as the vehicle that we will use to integrate retail price trigger Demand Response programs into wholesale market operations at the California ISO. PDR bids will be awarded and settled in a manner that is comparable to supply side resources.

Our major interest in this proceeding has been to assure that the Commission's final rule will support the progress that we have made in developing effective retail demand response programs, and integrating them into wholesale markets.

We are pleased that the Commission approved the California ISO's PDR tariff filing last July. We think

that is an important step forward to effective integration of retail Demand Response into wholesale markets.

We support the proposed rule's conclusion that Demand Response compensation in wholesale markets should be at the LMP This is consistent with how PDR is designed. While we agree with those who recommend an adjustment for retail bill savings—the so-called "minus G" adjustment—we believe that this is properly the jurisdiction of state regulatory agencies, and that FERC should neither require [162] nor enjoin the use of a Minus G adjustment at retail.

Let me turn to the issue of Cost Allocation and talk a little bit about how the PDR handles Cost Allocation. It appears from the discussion in the supplemental NOPR that some parties are viewing the payments made to Demand Response participants as an Uplift, or an Out-of-Market Cost that needs to be assigned to some class of market participants.

That isn't the way things function in the California PDR. Under PDR, consumer reductions electricity consumption are treated as a supply element and paid at the LMP, just like a supply resource.

As a result, these load reductions do not create Uplift or Out-of-Market Cost that needs to be allocated. Instead, the amount of consumer load reduction is added to the recorded usage of the participating consumer's load-serving entity.

This balances the books. It means that the Minus load for the Demand Response provider is offset by Plus load for the LSE. It also means that the Minus LMP that goes to the Demand Response provider is balanced by a Plus LMP which is recovered from the market, from all demand, based on how demand brings energy into that market.

Thus, Demand Response resources are paid for by load-serving entities who choose to pay the full LMP in [163] order to obtain energy for their consumers. The key point is that this occurs through the normal settlement mechanisms in the wholesale market, and treats Demand Response in a manner that is analogous to supply resources without any Uplift or Out-of-Market Costs to be allocated.

So thank you for your attention. I look forward to any questions you may have at the conclusion of the panel.

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[176]

MS. WISERSKY: Thank you for the opportunity to speak today on this NOPR.

I am representing MG&E today and the Midwest TDUs. MG&E, Madison Gas & Electric, is an investor-owned public utility under the laws of the State of Wisconsin, and we are regulated by the Public Service Commission of Wisconsin, or I'll probably call it the Wisconsin Commission.

Among other things, we provide electric service to about 140,000 customers, residential, commercial, industrial, in southern Wisconsin. And our highest peak—wait for this—742 megawatts in 2006.

I'm also speaking on behalf of the Midwest Transmission Dependent Utilities, or TDUs. We're a group of transmission, like I said, dependent utilities, and we are all members of the Midwest ISO. I also would like to put in the plug that we're all from traditionally regulated, cost-of-service, obligation-to-serve type states.

I was going to actually in my comments today go off on a slightly different direction supporting—and we do support—the MISO approach. But really the big elephant in the room that hasn't been addressed, particularly in what I heard in the morning panel, is the role of the states.

When it comes right down to it, it is their—they [177] are the key decision makers for us in regard to Demand Response. They allow us to participate or not participate. And the whole compensation issue for us, and especially with our utility demand programs, is all developed through our ratemaking process through our rate cases, and such.

So from our point of view, paying full LMP instead of doing something like LMP Minus G, we're talking about subsidy, in our opinion. And if there is a subsidy, none of the Cost Allocation proposals will work. They all have problems because it doesn't deal with the

"missing money" problem appropriately. And, as mentioned in earlier panelists, we believe that actually will retard Demand Response development, particularly with utilities such as MG&E.

And also, because we are in the Midwest ISO dominated by traditionally regulated states, that regional variation and experimentation, instead of one-size-fits-all policy, is very important.

Let me—I have already mentioned, probably used and abused MG&E's DR program a little bit already—these aren't new programs. We were first directed to create these in 1984, and they are meant for reliability purposes, and they've served us very well.

We have about 50 megawatts of Demand Response split roughly into two different types, a commercial, [178] industrial interruptible program, and these customers through the rates are paid a monthly bill credit.

They also get a bill reduction if we do interrupt them. They are not consuming energy. And the other 25 megawatts, roughly—it's a residential air conditioning program, and these customers are compensated when we actually use the program.

Now what our Demand Response programs represent is basically—this is nonfirm load. We don't do planning for them. And this has allowed us to—you know, at 50 megawatts that's roughly, you know, it's a small peaker that we haven't had to build or go into a purchase power agreement with someone.

And we use these programs in the Midwest ISO both in terms of the ASM market, the ancillary services market, and we're in part of the Emergency Demand Response.

The Commission's actions on this NOPR we believe should be guided by Order 719A, and that the Commission was not intending that existing Demand Response programs, whose benefits are well known, would somehow be endangered or put on the chopping block.

I would say that we support the MISO-type approach to this, which is essentially LMP Minus G, because we believe if you do that, make that adjustment, you can assign the cost of that DR to the utility and you don't [179] socialize or uplift these costs to any other customers.

Given this Commission's limited role with respect to retail Demand Response, we think it makes sense to allow the RTOs to work with the state regulators to develop DR compensation and Cost Allocation policy that meets the needs of the states that are in the region, such as MISO. And MISO is very different from the New York ISO, ISO New England, PJM, and such.

So as long as you have this "missing money," if you're going to socialize or uplift this cost, the allocation process just does not work properly. One of the things that at MG&E we kind of, we jokingly say is "load always pays." I don't care how you—if you

charge transmission owners or such, somehow, you know, all that money gets funneled back to load. So that's where it's very important to consider the compensation in DR and how it affects utilities and the customers of utilities such as MG&E. Because—and this may sound a little vulgar, but it in our mind is just basically wrong to stick the G costs to the LSE.

So in conclusion, we believe that standardizing the compensation and Cost Allocation is not warranted at that time. Like I said earlier, one size does not fit all. And the Commission has had a long history of allowing regional variation to meet regional needs and conditions, [180] and we hope that the same philosophy will continue on in this NOPR.

Please welcome experimentation and keep an open mind to different types of compensation and allocation designs. Thank you, and I look forward to the question and answer period.

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MR. HUNTER: All right. I'll come back to you, Tim. I heard a couple of people mention the term "missing money," and again I want maybe a clarification here that may generate some discussion.

I think the standard understanding of that term is that when you have Demand Response providers being paid full LMP, unlike the case where you have buyers and sellers and for every megawatt that gets bought

there's a seller providing it and the money gets matched up, pretty clearly here there is this "missing money", the money that is not being—there's not a buyer that's paying for this energy that's not being consumed.

I heard a couple of people mention it, I think Angie wasn't sure it existed. I just want to make sure we're on the same page with what it is. And, if so, how those costs should be allocated.

So any thoughts on that? Thank you.

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MR. HUNTER: Yes, Megan, please.

MS. WISERSKY: Thank you. I was thinking of it as very close to what Ken was saying, that there is a mismatch between the amount of megawatt hours we as an LSE are charged for and what our retail meters show that were actually consumed. So it's missing megawatt hours with associated rates that we would have received, or revenues we would have received as the LSE.

So that's the mismatch for us. And it gets back to—and it was stated this morning—that what the demand responder is doing by paying the retail rate is essentially buying from us a service right, that it's in turn selling into the wholesale market.

[193]

And from our point of view, if that is done, if we are compensated for that, then it becomes, when we're talking about broader Cost Allocations, it's almost that then you're dealing with a resource that's almost more like a generator that's within your service area.

So then, if you look at the ways LMPs are constituted, then, yeah, the LSE that's within that area, because the prices of that generator are going to affect the local LMP more so than—you know, in Madison than they are somewhere in the far reaches of southern Indiana.

So then in that case, if you reconstitute the load as what Mike had said, you—the host LSE—the cost of the DR can be allocated to the host LSE.

MR. HUNTER: All right, thanks. Carl?

MR. SILSBEE: I agree with Megan's definition of "missing money" Let me give a simple example of where I see the problem.

Let's say that we have a 500 kW customer, and that customer has contracted with a Demand Response provider to supply 400 kW of load reduction, and bids it, and it's called. Under the way the PDR works in California, the customer would reduce load to 100 kW, but we as the LSE would still pay, or be responsible for 500 kW in wholesale markets. And we're okay with that. We probably had planned and bought power to serve that 500 kW in advance.

[194]

Where we run into problems is, we'd also planned to get 500 kW of payment at retail from the customer. And now the customer is only seeing meter spin of 100 kW. So there's 400 kW of retail payment that we didn't get. And that's why we're looking to the state to find some way to compensate us for the loss of compensation at retail, the Minus G.

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OHIO COMMISSIONER CENTOLELLA: Well I wanted to both agree with Carl's characterization of what the "missing money" problem is, but suggest that it is really not tenable to put that responsibility back on the states.

I mean, the ultimate, you know, fact that, you know, what Carl's illustration demonstrates is that you really do have a subsidy or an incentives which goes beyond what is efficient in terms of the payment to the Demand Responder in this instance.

And you are now putting the state in the position where if we were to try to get back to an efficient level of incentives, we would be having to in effect issue a charge for energy that was not consumed. We would be doing what would be perceived as a take-back by that customer. And that would put us in a very difficult position.

Alternatively, I suppose we could, if it were subject to our jurisdiction, spread it to other customers of [198] that utility. But it may well not be subject to our jurisdiction. It may be a competitive LSE for which we have no authority over it, in which case the LSE may simply end up being squeezed in that situation based upon their existing contractual commitments.

So I think that, if one wants to make this clean and transparent, the right thing to do is to get the incentives right at the wholesale level by doing LMP Minus G. And not attempt to force it back onto the states to correct what is in effect an untenable kind of situation.

So I guess the question then becomes: Does the additional incentive of not recovering G, is this a sensible incentive from the standpoint of promoting increased Demand Response? And I would suggest that it is not directly related to what's necessary to incent additional Demand Response. It may be more.

It may in some instances even be less than what's necessary. But it is directly tied to whatever that customer's retail rate was, and not to some specific either market failure or other policy objective that you're trying to incent by incenting more Demand Response. What you're doing is you're creating incentives which vary by customer based on what that customer's retail generation rate is. And it is not clear to me why that additional incentive is at all rational.

[199]

MR. HUNTER: Thank you. Commissioner Moeller?

COMMISSIONER MOELLER: Thanks, David.

I want to get back—Carl, I must be missing something in your example. So as the LSE you are still required to procure the 500 kW. The DR provider bids in the 400. But isn't it in your interest then to resell that 400, in which case there hasn't actually been a decrease in demand?

MR. SILSBEE: We run our own Demand Response programs where we seek reduction from the customers, but at wholesale Demand Response providers are free to enter that game as well and may participate.

If the customer wants to go to a third party Demand Response provider, that's fine. That's their choice. We stand by to serve them the 500, if they want to pay for it. We also appreciate the importance of a price signal. And if they want to reduce their usage by working through a Demand Response provider, we have no objection to that.

As I said in my prepared remarks, everything balances out. It's Minus 400 from the DRP with the participating customer behind them, plus 400 on our books, and the LMPs work out as well.

What we want is to get a retail payment back from the DRP or the customer. The mechanism by which

we do that is still something that we hope the California Public [200] Utilities Commission will address.

And I realize that retail payment at the specific time in which the DR payment—or the DR Program is called, may not be the same because of the blending of the rate, and perhaps the socialization of that rate. But that's really an issue with state ratemaking that needs to get sorted out by the state, in my view.

COMMISSIONER MOELLER: Okay. Thanks.

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MS. WISERSKY: Thanks. I just wanted to chime in about how important this "missing money" has been to the Wisconsin Commission. The Wisconsin Commission—let me get my words right here—they temporarily barred the participation, the direct transfer of DR into the MISO market, or the operation of a third party arc, mostly because although they recognize there might be some advantages, they were very concerned about any discriminatory effect that this might have, and the financial implications to ratepayers, the electric utilities.

And how we plan, or how we do our long-term planning, is I did mention that our utility-based programs are nonfirm load that we don't carry reserves. So there is a question about what happens to that if you cut that Demand Response loose from the LSE in this type of regulated state, what happens to it?

And I'm just quoting now, it's—the filing for that was, or I'll paraphrase it: The Wisconsin Commission was concerned about this approach could end up, or had the [203] potential for securing electricity at net lower rates than are authorized by the commission. So the Wisconsin Commission did recognize that there is a, potentially a "missing money" problem that could arise.

Thanks.

MR. HUNTER: And Michael from the Midwest ISO has had it up for awhile.

MR. ROBINSON: Sure. Thanks. I wanted to support what Commissioner Centolella was saying earlier about how, if you sort of let this get sorted out at the retail level between the state jurisdictional authority, the LSE, and the third party provider, there could be some significant issues from either a statute basis or just some significant problems.

The Midwest ISO recognized that. And so in our original proposal, as I mentioned earlier, we did support paying LMP and then charging the LSE LMP. And letting those monies that flow between the counterparties, the third party provider and the LSE, get sorted out at the retail regulatory authority level.

We heard loud and clear from the organization of MISO states and other retail jurisdictional entities about all of the issues that would be associated with that, and the problems. And so—and in addition, we recognized that we had certain efficiencies and econo-

mies where we could [204] actually accomplish that much cheaper than the state jurisdictional entities.

So in our final proposal we offered to provide that service to essentially—we didn't call it the G, LMP Minus G, but we called it the "Marginal Foregone Retail Rate" to recognize the fact, as Paul said, that the retail, the avoided retail revenues could vary by market segment, by market participant, by state, by utility.

So we have the tools in place currently to accommodate whatever the Marginal Foregone Retail Rate would be as specified by the retail regulatory authority.

MR. HUNTER: Professor Hogan?

PROFESSOR HOGAN: I would like to come back to Commissioner Moeller's question and come at it a slightly different way and pose a question.

It seems to me—and also to deal with Paul's concern, which I think is legitimate—this is a FERC program. We're talking about wholesale market Demand Response participation, which people volunteer for. They're not required to do it.

So I don't understand why FERC can't condition it and just take a very simple model that, it seems to me, would work. Which is that, you can sell into the wholesale market any electricity you've purchased. If you purchase electricity and you don't consume some of it, you can sell [205] it back and we'll pay you the

LMP. But you have to purchase it. So now it's a contractual arrangement, and they can purchase it on their whatever-arrangements they have. They can get it through their retail rate. They can do it with their competitive load serving entity. They generate it themselves. And then we'll purchase it back at LMP. Now we can all go home.

Why couldn't FERC do that? That would be efficient. It would be simple. There'd be no Net Benefits test. There's no Cost Allocation. It's consistent with all the rhetoric about even-handed participation in the marketplace. We're done.

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OHIO COMMISSIONER CENTOLELLA: I want to go back and comment on one thing that Ken said, because I think actually, Ken, you said something that I agree with, and I [211] want to—but I want to take it in a direction which may not be the direction that you intended it.

You said that we have inefficient markets when it comes to Demand Response, and we ought to do something to correct that inefficiency. And I would agree. You know, there are inefficiencies in the fact that, you know, we don't have the measurement to do Demand Response in real-time for many consumers.

There are information asymmetries. We have consumers who don't even know what a kilowatt hour

is, let alone the fact that it could cost more on-peak than off-peak. And, you know, there are things about the demand side of the market that are inefficient.

Where I have a problem is I don't see the payment of LMP plus the avoidance of the retail generation cost as being somehow linked in an efficient way to correct those inefficiencies.

If we were having a different discussion today about who should be paying for advanced metering, or who should be paying for information displays that allow consumers to know what it cost them to buy electricity which are the kinds of debates that we have in our state, this would be a very different discussion I think.

But I know, you know, the issue is that we've kind of latched onto this notion of paying full LMP plus [212] avoidance of the retail generation charge, and we have not asked the question of what is the most efficient way in which we as regulators, or we as market participants, could overcome the specific reasons why the demand side of the market is less efficient than we would like it to be.

And I think it would be much more productive for us to have that discussion than for us to have this discussion of paying full LMP versus LMP Minus G.

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OHIO COMMISSIONER CENTOLELLA: I guess I wanted [232] to respond again to something that Ken said a moment ago. Sorry, Ken, I keep picking on you, but you talked about the consumers enjoy the fact that LMPs would be lower.

I mean, there are some other issues with that, but I think one of the assumptions that is out here is that the only way, you know, that demand is going to respond is somehow if we get it bid into the wholesale market.

And I have a significant concern that we are putting a big weight on one side of the scale here of how Demand Response develops, and ignoring potential others ways in which demand could simply respond to price and develop much more efficiently. I mean, we have got appliance manufacturers out there who tell us, who are working on SmartGrid, that if they could simply see prices they would have their appliances automatically respond to them.

We have controls vendors. We have companies like MicroSoft and Google who are ready to automate people's houses. We have buildings that are being automated to provide regulation in PJM, you know, that don't depend on having an intermediary come in and be subsidized by this extra incentive in order to bid into a wholesale market program.

And I am concerned that we are potentially distorting innovation on the demand side of this market if

what we do is selectively say we're going to pay an [233] additional incentive to people who participate in economic RTO programs when that same incentive is not available to consumers who are simply responding to a dynamic retail price.

And I think that ought to be a significant concern in terms of the competitiveness of the U.S. economy and where we are in terms of encouraging innovation in this country going forward. And so I think if we're going to talk about additional incentives, we need to think about how we do this in a more neutral fashion and in a way that will potentially get us further ahead, rather than assuming the only way we're going to do this is by having an aggregator bid that into a wholesale market. Because we may be passing up even more Demand Response benefits by putting a weight on that side of the scale.

MR. HUNTER: Thanks. So I would like to pose a final question I think for—Oh, sure.

CHAIRMAN WELLINGHOFF: Paul, I can't resist.

(Laughter.)

CHAIRMAN WELLINGHOFF: With that speech, I am going to have to jump in here. Angie Beehler over there didn't put in all the technology she put in because of dynamic retail prices. Jay Brew's people didn't put in all the technology they put in because of dynamic retail prices. They put it in because

they had the opportunity to bid in [234] wholesale markets.

So again, with all due respect, I believe the complete opposite. I think wholesale markets for Demand Response have in fact fostered technology, and in fact will foster it much faster than the states will, because I have no assurances as to when the states will put in dynamic retail prices with the controversies that are going on, all the political problems with getting those in place.

I think the only way we are going to get this technology in place and we're going to move forward with it is to move forward with it in the wholesale markets.

MR. HUNTER: Commissioner Moeller?

COMMISSIONER MOELLER: And I have the opposite view. I am all with you, Paul. I think without dynamic pricing we have the serious potential of residential consumers subsidizing wholesale consumers, and that worries me greatly. And I think the key is shifting demand, and we've got to do it through dynamic pricing.

If we do this wrong, we will have the opposite effect. So I respectfully disagree with my Chairman.

MR. HUNTER: Anything else?

(Laughter.)

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MR. HUNTER: All right. Thanks for coming, and with that we are done.

(Whereupon, at 3:22 p.m., Monday, September 13, 2010, the technical conference in the above-entitled matter was adjourned.)

UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. RM10-17-000

DEMAND RESPONSE COMPENSATION IN ORGANIZED
WHOLESALE ENERGY MARKETS

Sept. 13, 2010

WRITTEN STATEMENT OF MEGAN WISERSKY ON BEHALF OF MADISON GAS AND ELECTRIC COMPANY AND MIDWEST TDUS FOR THE SEPTEMBER 13 TECHNICAL CONFERENCE

Thank you for the opportunity to participate on behalf of Madison Gas and Electric ("MGE") and Midwest Transmission Dependent Utilities ("Midwest TDUs"), in today's important technical conference.

I am Megan Wisersky. I am Manager of Electric Planning at Madison Gas and Electric Company, a public utility organized under the laws of the State of Wisconsin. MGE is engaged in the generation, purchase, and distribution of electric energy, and the distribution of natural gas, in an area of southern Wisconsin that has Madison as its hub. MGE provides electric service to residential, commercial, and industrial customers (some 140,000 meters in total) in an area covering approximately 250 square miles, with a

2006 peak load of 742 MW and annual sales of approximately 3 million MWh. The service MGE provides to its retail customers is regulated by the Public Service Commission of Wisconsin ("PSCW").

I am also speaking today on behalf of Midwest TDUs, a group of transmission-dependent load-serving entities that must participate in the organized markets of the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO" or "MISO"). In addition to MGE, Midwest TDUs consist of Missouri River Energy Services, Missouri Joint Municipal Electric Utility Commission, Midwest Municipal Transmission Group, Southern Minnesota Municipal Power Agency, and WPPI Energy.

Our panel has been asked to address cost allocation issues associated with compensation of retail demand response sold into wholesale energy markets. To give you MGE's and Midwest TDUs' perspective on these two intertwined aspects of demand response, I will first provide some background on MGE's PSCW-established reliability-based demand response programs. I then describe MISO's integrated approach to demand response compensation and cost allocation; explain why it is well-suited to MISO's region, which is dominated by traditional obligation-to-serve states whose retail regulators support MISO's approach; and why there is no basis to conclude that MISO's integrated approach is unjust and unreasonable, warranting the reforms proposed in the NOPR. I will also explain our concerns with the DR compensation pro-

posal in the NOPR, which would aggravate the cost allocation issue and make it harder to solve.

My ultimate conclusion is that this is not the time to standardize demand response compensation and cost allocation. The Energy Policy Act of 2005 established that "[i]t is the policy of the United States to encourage States to coordinate, on a regional basis, State energy policies to provide reliable and affordable demand response services to the public."[1] Consistent with Congress' directive, and because retail demand response is of necessity largely in the control of retail regulators, the Commission should allow each region to work with the retail regulators in its footprint to develop programs that work for the region, as MISO has done. Allowing regional experimentation with demand response compensation and cost allocation schemes will enable assessment of their efficacy, and will allow regions to develop solutions tailored, so that they do not undermine existing reliability-based demand response programs. In fact, Commission action to prematurely adopt a standardized market design for demand response compensation and cost allocation would likely do more harm than good, and increase resistance from the state regulators whose support and cooperation is essential to any retail demand response effort.

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[1] Energy Policy Act of 2005, Section 1252(e)(1), 16 U.S.C. § 2642(e)(1); *see also id.*, Section 1252(f), 16 U.S.C. § 2642(f) (stating that it is the policy of the United States to encourage "time-based pricing and other forms of demand response").

A. MGE's Demand Response Programs

Demand response is not new. As directed by the PSCW, MGE has had its existing demand response programs in place since 1984. These programs are intended to enhance reliability and reduce MGE's power supply costs, and have achieved those purposes.

Approximately 25 MW of MGE's commercial and industrial load is under an interruptible schedule. These customers receive a reduction on their demand charges all year round in exchange for giving MGE the right to interrupt them in specified conditions. MGE has another 25 MW of residential air conditioning load, consisting of some 16,000 residential customers, that is subject to MGE's control with compensation.

Year in and year out, these demand response programs provide value to the retail customers served by MGE. These programs give MGE the flexibility to interrupt 50 MW of load to maintain reliability. They relieve MGE of the obligation to plan resources to serve that load and to carry reserves for that load. In fact, before authorizing any new large electric generating facilities, PSCW requires MGE to demonstrate that the associated need for supply cannot be met with energy conservation and efficiency.[2] In addition, under the MISO tariff, MGE can use its existing demand response programs to provide Emergency De-

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[2] Wis. Stat. § 1.12(4)(a); Wis. Admin. Code PSC § 111.53(d)(1).

mand Response to MISO, which gives MISO greater tools to deal with reliability challenges.

Thus, MGE's ratepayers reap significant value from its existing demand response programs. Other Midwest TDUs have similarly reduced costs through reliability-based demand response programs. These programs, whose effectiveness has been recognized by the Commission Staff,[3] should be preserved. The Commission's actions on this NOPR should be guided by Order 719-A's statement that the Commission was not intending to disrupt existing demand response programs.[4]

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[3] The 2007 FERC Staff Assessment of Demand Response and Advanced Metering (at 7) found load reductions in demand bidding programs of only 4-19% of enrolled demand response resources, and FERC's 2007 report distinguished between "economic" (demand bidding) DR (which is not as effective, *i.e.*, <20% response rate) and "reliability-based" DR (which has a much higher response rate—62% and 83% in the programs reported in the 2007 Staff Assessment). *Available at* http://www.ferc.gov/legal/staff-reports/09-07-demand-response.pdf.

[4] Order No. 719-A, P. 67 ("The intent of the Final Rule is not to interfere with, undermine, or change existing demand response programs. Nothing in the Final Rule would require a state or local regulator to take any action or prevent them from: (1) preserving existing aggregation programs, in whatever fashion is appropriate for its jurisdictional area; or (2) authorizing retail customers, via an ARC, to participate in wholesale markets.").

B. MISO's Demand Response Compensation and Cost Allocation Proposal Makes Sense.

In response to Order 719, MISO worked with its stakeholders and the state regulators in the thirteen states included in the MISO footprint, to develop a wholesale-market-based retail demand response compensation and cost allocation program that worked for its region.

The MISO proposal compensates retail demand response sold into wholesale energy markets at LMP minus the Marginal Foregone Retail Rate ("MFRR"). Under this compensation scheme, the demand responder receives the LMP price signal in two parts: (1) the savings from avoiding the marginal retail purchase price; plus (2) the difference between the LMP and the marginal retail purchase price. Combining these two elements, the retail demand responder "sees the actual LMP," enabling it to make economically efficient consumption decisions. Financially, this approach treats the retail demand responder as effectively purchasing from the LSE the retail service right it is reselling to the RTO as demand response.

This demand response compensation scheme fits together well with MISO's proposed allocation of the costs to the host LSE of the demand responder. It is fair to LSEs (the wholesale transmission customer that FERC needs to protect from unjust and unreasonable rates), because the LSE is in the same financial position as if it had sold energy to the DR customer which turned around to resell it to the RTO. The

LSE and its retail rate regulator still have to address the billing determinant mismatch through retail rate design and cost allocation (since MISO will treat the LSE as having purchased more MWhs of energy than the LSE's retail meters show its retail customers consumed). However, the LSE is not underwriting demand response of other LSEs or the retail demand response approach of other state regulators, and it is not providing duplicative compensation to the retail customer that has chosen to sell its demand response into the wholesale energy market. It thus facilitates the ability of regulators and LSEs to accommodate and preserve existing demand response programs.

C. There is No Basis to Override Programs that Fail to Pay Demand Responders the "Full LMP," Plus their Avoided Retail Purchase Savings.

As comments filed in this proceeding show, there is no basis to conclude that a compensation scheme like MISO's, that fails to pay retail demand responders the full LMP for energy on top of their avoided retail purchase savings, is unjust and unreasonable.

The NOPR has been strongly opposed as unjustified on economic grounds. While I'm not an economist, I noticed that not only does the FTC think that the two-part compensation approach (like that proposed by MISO) is economically sound, so do other economists that FERC has relied upon, for example, Bill Hogan, PJM's market monitor, and MISO's market monitor. Just a few years ago, in *PJM Industrial*

Customer Coalition v. PJM Interconnection, L.L.C., 121 FERC ¶ 61,315 (2007), the Commission itself reached the opposite conclusion to the one that it relies upon as justification for its proposed rule. There, the Commission characterized full-LMP compensation for sales of demand response resources as including a system subsidy for these resources, declined to permanently maintain such a subsidy, and held that elimination of the subsidy does *not* make rates unjust and unreasonable.

The NOPR's compensation proposal seems to be at cross purposes to Congress' policy of encouraging price responsive demand through direct exposure to dynamic prices reflecting the LMP, *e.g.*, through smart meters.[5] The excessive, LMP-plus compensation received by retail demand responders under the NOPR's proposal would certainly be preferred by those demand responders—particularly if they can also enjoy the protection of average embedded-cost retail rates should they decide in any given hour that they do not want to drop load. And dynamic pricing for retail customers will only *increase* the dollar value of the LMP-plus compensation a demand responder could receive, and the missing money to be allocated, under the Commission's proposal. Why bother with time-based or other forms of dynamic pricing, along with the smart meters to implement such pricing, if

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[5] *See* Energy Policy Act of 2005, Section 1252(f), 16 U.S.C. § 2642(f).

this Commission adopts a compensation scheme premised on the assumption that exposing retail customers to the LMP is not enough to induce efficient behavior and which reinforces that assumption, so that it becomes a self-fulfilling prophecy?

Further, given the Commission's limited role with respect to retail demand response, it makes sense to allow RTOs to work cooperatively with state regulators to develop a demand response compensation and cost allocation program that meets the needs of states in the region, as MISO has done. As Order 719 correctly recognizes, it is up to the relevant electric retail regulatory authority ("RERRA") to decide whether to allow retail customers to bid their demand response into organized wholesale markets.

For example, in response to Orders 719 and 719-A, the PSCW has temporarily barred the transfer of demand response load reductions to MISO generation markets directly by retail customers or by third-party aggregators of retail customers ("ARCs")[6]

> to prevent potential unlawful discrimination and to permit the Commission additional time to gather more information regarding ARCs, ARC compensation and the tariff provisions of the Midwest In-

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[6] Order Temporarily Prohibiting Operation of Aggregators or Retail Customers at 1, PSCW Docket No. 5-UI-116, Investigation to Develop and Analyze Alternative Electric and National Gas Design Options which have the Potential to Reduce Emissions of Greenhouse Gases (Oct. 14, 2009).

> dependent Transmission System Operator, Inc. ("MISO"). Temporarily prohibiting ARCs will provide the Commission with an opportunity to analyze the financial implications that ARCs may have for Wisconsin ratepayers and electric utilities and to investigate the effects that ARCs may have on utility-sponsored demand response programs and utility planning.

After recognizing that ARCs may provide some advantages, the PSCW explained its concerns:[7]

> [T]he Commission's preliminary investigation reveals that customers selling load reductions through ARCs, or acting as ARCs themselves, have the potential for securing electricity at net lower rates than authorized by the Commission. Utilities could also be left with the legal responsibility and the associated costs of providing adequate generating capacity for customers which are reselling such capacity into the wholesale market through an ARC. Such outcomes could impose additional costs on other ratepayers and could be discriminatory.

As also noted by the PSCW, MISO's proposal has not yet been approved by FERC.

Adoption by this Commission of a demand response compensation rule that prohibits the solution MISO worked out with its state regulators, and which was

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[7] *Id.* at 3-4.

supported by the Organization of MISO States ("OMS"), is more likely to create new barriers to demand response than eliminate them. For example, the NOPR's proposal to over-compensate retail customers for demand response would exacerbate the discrimination concerns identified by the PSCW.

The NOPR's proposal to effectively pay DR more than the LMP, creates a much more difficult cost allocation issue than MISO's proposal. For one thing, the NOPR's "LMP-plus-savings" compensation results in a much bigger amount of "missing money" than MISO's approach. In addition, the NOPR's proposal to over-pay for demand response as an inducement to get retail customers to forego consumption to reduce regional LMP does not mesh, from a cost causation/benefits perspective, with assigning the resulting significant costs to the host LSE, as MISO's proposed method does.

But more broadly allocating the missing money creates its own set of problems. Uplift would require MGE ratepayers, for example, to pay for 100% of MGE's state-mandated demand response programs, *plus* a share of the demand response of LSEs that may not have such robust reliability-based DR programs. By financially punishing LSEs with strong existing retail demand response programs, it thus runs contrary to Order 719's stated intent not to interfere with existing DR programs. It will also create friction in a multi-state region where the retail regulators in different states may have adopted differing retail demand

response policies. In addition, broader allocation, where LSEs loads are not reconstituted for settlement purposes, leaves LSEs exposed to deviation charges (in MISO, Revenue Sufficiency Guarantee charges) for real time deviations.[8]

Broader cost allocation assumes the region-wide LMP is reduced by demand response, an assumption that depends on constraints. It matters where the retail customers providing demand response are physically located. Energy price is local, which is why you don't have the same LMP across the entire MISO footprint. You have local constraints, local congestion, and LMP differentiation. It doesn't make sense in terms of cost allocation to require RTO-wide socialization and uplift for retail demand response sold into wholesale energy markets, when we don't socialize and uplift for energy from bricks and mortar generators.

If, in the alternative, the uplift of the missing money were limited only to the loads at nodes where the LMP changed as a result of the demand response resource, would the RTO have to run a complete parallel, hypothetical model to identify the prices that would have existed in the absence of the demand response energy? And would the costs of implementing that complicated system of shadow market models far

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[8] Elimination of deviation charges for real time reductions when MISO calls for an emergency, as required by Order 719, would likely cover only a subset of the demand response usage.

outweigh any potential system benefits from demand response sales into energy markets?

As some of the comments submitted in this proceeding illustrate, efforts to accommodate a broader cost allocation may well involve a full redesign of the whole market algorithm and settlement scheme, potentially including how the LMP itself is calculated. All this effort will be very expensive, increase complexity, and potentially create new gaming opportunities, even beyond the vexing verification issues inherent in certifying retail demand response as a wholesale resource. The prospect of redesigning the settlement system to charge LSEs throughout the MISO region at a level *above* the actual LMP, in order to recover the LMP-plus compensation provided to the demand responders, is hardly a positive advertisement for the consumer benefit gained by this approach.

Adding a net benefits test might make the beneficiaries-based cost causation proposal more superficially plausible, but won't solve the underlining problems I've identified above. And it will add even more complexity.

These concerns demonstrate that standardization of demand response compensation and cost allocation is not warranted at this time. Even if the Commission leaves it to each RTO to sort out the very difficult market redesign implementation problems, a Commission directive to standardize demand response compensation and cost allocation amounts to a new "SMD" in a context where there is a strong imperative to allow

regional variation to accommodate the retail regulators whose consent is a necessary ingredient to making demand response work.

One size does not fit all. MISO's approach works in the Midwest, where the states are predominantly traditional obligation-to-serve states. A different approach may be appropriate in regions where the retail regulatory context is different. Each RTO also has different settlement schemes, and different hardware and software, that may be more or less adaptable to different approaches.

Fundamentally, it is much too early to cut off regional experimentation and to standardize a single "right answer" to the hotly debated tangle of issues surrounding the compensation/cost allocation for sales of retail demand response into wholesale energy markets. Contrary to the NOPR's suggestion, PJM's experience does not demonstrate a failure of the MISO approach to compensation. As the report of PJM's IMM makes clear, "[t]he evidence does not support the claim that the removal of the [PJM demand response] incentive program resulted in a reduction of activity in the [PJM demand response program],"[9] since other

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[9] Monitoring Analytics, Barriers to Demand Side Response in PJM 22, Docket No. RM07-19-000 (July 1, 2009) ("Market Monitor Report"), *available at* eLibrary Accession No. 20090701-5305; *see also* Demand Response Compensation in Organized Wholesale Energy Markets, 75 Fed. Reg. 15,362, 15,370 & n.6 (proposed Mar. 29, 2010), FERC Stats. & Regs. ¶ 32,656, at 33,998 & n.6 (2010) (Moeller, Comm'r concurring in part and dissenting in part), *sup-*

unrelated factors—including a tightening of the demand response verification process and lower average PJM price levels due to the economic downturn—may have been responsible for the change.

The Commission should not assume that MISO's OMS-supported approach is inadequate before it is even tried. Experience with a variety of programs in different RTOs should provide data that plainly do not exist today to assess the effectiveness of various approaches, support more rational policy judgments by this Commission, and bring along the retail regulators whose cooperation is critical to the success of DR programs.

Again, I appreciate the opportunity to address these important issues and look forward to your questions.

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plemented, 75 Fed. Reg. 47,499 (proposed Aug. 6, 2010), 132 FERC ¶ 61,094 (2010).

UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. RM10-17-000

DEMAND RESPONSE COMPENSATION IN ORGANIZED
WHOLESALE ENERGY MARKETS

Oct. 13, 2010

POST-TECHNICAL CONFERENCE COMMENTS OF THE AMERICAN PUBLIC POWER ASSOCIATION

The American Public Power Association ("APPA") submits its post-technical conference comments in accordance with the Commission's "Supplemental Notice of Technical Conference and Notice of Comment Date" issued in the above-noted docket on August 27, 2010.[1] The Commission on September 13, 2010, held a full-day Staff-led Technical Conference to explore certain issues raised in the comments filed regarding the Commission's Notice of Proposed Rulemaking ("NOPR") issued in this proceeding on March 18, 2010.[2] APPA files these comments to express its

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[1] 75 Fed. Reg. 54,063 (September 3, 2010).

[2] *Demand Response Compensation in Organized Wholesale Energy Markets*, 75 Fed. Reg. 15,362 (March 29, 2010). The NOPR proposes to amend Chapter I, Title 18, Section 35.28 of the *Code of Federal Regulations* by adding a new paragraph (g)(1)(v):

views on certain issues raised at the Technical Conference.

As APPA noted in joint comments filed with the National Rural Electric Cooperative Association ("NRECA") in this docket on May 13, 2010, APPA welcomes an inquiry into the compensation of demand response bidders in markets operated by Regional Transmission Organizations ("RTOs"), but it cannot support the NOPR in its current form. While many of the RTO-run centralized markets have demand response programs that use locational marginal prices ("LMPs") as a tool to incent economic demand response, the exact formulation varies among the RTO-run markets. APPA believes it is wiser to allow RTOs and the stakeholders in their regions to implement their own variations on demand response incentives in response to local and regional needs, rather than for the Commission to prescribe only one method of compensation.

The presentations at the Technical Conference only reinforce this conclusion. APPA was struck by the

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§ 35.28 Non-discriminatory open access transmission tariff. (v) Demand response compensation in energy markets. Each Commission-approved independent system operator or regional transmission organization that has a tariff provision permitting demand response resources to participate as a resource in the energy market by reducing consumption of electric energy from their expected levels in response to price signals must pay to those demand response providers, in all hours, the market price for energy for these reductions.

diversity of positions that the various speakers took, and the "strange bedfellows" coalitions that seemed to develop during the course of the day:

Third-Party Aggregators and Industrial/Large Commercial Customers. The strongest proponents for payment of "full LMP" to providers of wholesale demand response services[3] came from those entities that stand to benefit the most—third-party aggregators of demand response ("ARCs")[4] and large users of electricity, such as industrial customers and large commercial customers.[5] This is certainly understandable.

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[3] APPA believes that "wholesale demand response" is in some ways an oxymoron, in that demand response is, at its root, a retail activity. This fact gives rise to many of the problems with the Commission's NOPR proposal.

[4] *See, e.g.*, Statement of Audrey Zibelman for Viridity Energy, Transcript at 35-36 ("The second thing is I would recommend that the Commission at a minimum say that there will be absolutely no Net Benefits test applied in the day-ahead market. Getting load in the real-time, in the day-ahead dispatch is going to be hugely valuable from the perspective of transparency, market liquidity, the ability for LSEs as well as virtual traders to start getting a real sense of elasticity of load—and again we're talking about controllable load, not all load.").

[5] Statement of Robert Weishaar for the Demand Response Supporters Group, Transcript at 45-46 ("The bottom line is that if supply side resources are permitted to find on their own the price point at which continued output becomes economic, then demand side resources should also be permitted to find on their own the price point at which continued output becomes economic. Administrative intervention is not necessary."); Statement of Donald Sipe for the Consumer Demand Response Initiative, Transcript at 40-41

The business model of for-profit ARCs depends on maximizing the revenues received from sales of demand response into wholesale markets; it increases the revenue pie they share with their aggregated retail loads.[6] And APPA can sympathize with industrial customers seeking the payment of full LMP for their demand reductions. Electric restructuring has not turned out as industrial customer advocates had hoped; in fact, they have paid substantially higher prices, instead of the lower prices that advocates of "deregulation" promised. They clearly wish to make up some of those losses through higher demand response revenues. But one must question whether it is always best from a societal standpoint for industrial

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("Setting artificial thresholds and tests that are not similar to generation resources doesn't allow the head-to-head competition, which is the whole point of what the NOPR is trying to do. So immediately when you begin to set those thresholds, you are backtracking from one of the major objectives that you set out to solve with the NOPR, and we recommend against it. CDRI has an approach that can operate as a Net Benefits test. It applies marginal cost pricing signals, and the information in marginal costs, to DR equally with generation. It rolls the additional cost of DR, because of billing unit effects, right into the day-ahead price, and it deals only with the day-ahead market."). Paul Peterson, appearing for the Public Interest Organizations, concurred in the CDRI proposal. Transcript at 51-52.

[6] Dr. Roy Shanker, Transcript at 116 ("If you're overcompensating people, understand where those subsidies go. Audrey's business is a lot tougher if it's LMP minus G than if it's LMP, because part of those subsidies will help her business. It's nothing against her business model, but that's the reality.").

plants to cease production and commercial activities to be curtailed so that demand response revenues can be earned, especially when the incentive rates they are responding to are not economically efficient in the first instance. These actions may be profit-maximizing for the individual industrial/commercial concerns in question, but may come at the price of decreased wages, less desirable working hours and a lower level of economic activity in the affected communities.[7]

Generators. The generator representatives appearing at the conference were firm in their conviction that payment of the full LMP to providers of wholesale demand response would entail payment of an unjusti-

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[7] *Cf.*, Statement of Jay Brew for the Steel Manufacturers Association, Transcript at 181 ("A typical electric arc furnace load is between 50 and 200 megawatts, that operates a batch process that takes about an hour from when you dump scrap into the furnace to where you tape a molten heat. And through the years, with the proper equipment, with the right investments, we've been able to disrupt that process in order to participate in these programs. There is a cost. If you've ever been to a steel mill, you do not want to interrupt that process. But we have."); Statement of Angela Beehler for Wal-Mart Stores, Inc., Transcript at 172-173 ("Participating in DR resource consumers, we do make sacrifices to supply DR service of curtailment. Consumers make payments for aggregator services. We sacrifice the comfort, convenience of family members in our homes, and the associates working within our businesses; consumers shopping our stores. We make adjustments to our manufacturing schedules, employee shifts, and invest in DR equipment to make these results happen.").

fied subsidy to such providers.[8] In their view, the cost of the retail electric service product which the retail customers choosing to reduce their usage did not purchase should be deducted from their payments, on the theory that they were in effect selling back into the market their "call option" on retail electric service.[9] Generators also expressed substantial concern that the Load-Serving Entities ("LSEs") standing by to serve

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[8] Statement of Joel Newton for the New England Power Generators Association, Transcript at 27 ("The proper way to conceptualize when to procure DR is that a particular consumer should forego consuming electricity when it would rather save the cost of consuming power than consume power. If the right price signal is given for this decision—and that, I submit, is LMP-minus-G, then there is no need for the benefits test."); Statement of Dr. Roy Shanker for the PJM Power Providers Group, Transcript at 60 ("If the Commission adopts the appropriate nondiscriminatory pricing for Demand Response, and payment of LMP minus the retail rate in the context of customers that face a fixed retail rate, then there is no need for a Net Benefits test.").

[9] Joel Newton, Transcript at 29 ("As Dr. Shanker explained, DR should be conceptualized as a call option. The consumer effectively purchases the option from the LSE to call electricity at a particular strike price. That is, the retail rate the consumer pays to the LSE."); Dr. Roy Shanker, Transcript at 69 (" [Y]ou can look at the fixed price retail arrangement as the LSE having sold a bunch of calls in the retail market. You can look at the payment of LMP as opposed to LMP minus the strike price as overpaying or overcompensating a group of parties that hold the call position, by the amount of the call position in excess of what the market price is, in order to suppress price in another market, in the wholesale market, where those same parties are very long or I'm sorry, are very net short, have large net short positions.").

such customers would have to absorb additional costs if the full LMP were paid to demand response providers.[10] APPA, as a trade association representing not-for-profit LSEs, was frankly taken aback by such expressions of concern, since generators are not generally so solicitous of the financial health of LSEs.

Regional Transmission Organizations. RTOs were generally of the view that, depending on the underlying retail rate structure, some level of deduction from the full LMP would be appropriate prior to payment,

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[10] Dr. Roy Shanker, Transcript at 71-73 (presenting a series of hypotheticals, some of which hold the LSE harmless, but others of which leave the LSE with an under-recovery of costs); Joel Newton, Transcript at 74-75 (" . . . [T]he call option is really between the LSE and the consumer. What's being proposed then by Professor Kahn then is that the consumer then has the right to sell its option, without having to do anything about the strike price that it agreed to enter into to the ISOs. That's really what his theory, the entire theory is, as to why they should be able to be paid the entire LMP and ignore the LSE all together. What we're saying is that actually the LSE is very important here, that the agreement by the consumer was to pay the strike price, and that is the retail rate to the LSE."); Statement of Dr. William Hogan, Transcript at 148 ("But the notion that you can ignore the retail rate I think is a perverse twist in the logic and it doesn't make any sense. We have to look through to that."); *but see*, Audrey Zibelman, Transcript at 78 ("So the suggestion that somehow or another we have to protect load-serving entities, because they're not quite sure how to manage a price structure, because you now have the demand, I think, is somewhat naive. They'll figure it out. They figured out everything else. The issue is is [*sic*] first to get the market developed; then the structures, whether they're long-term hedges, etcetera, will develop around that.").

and is in fact is necessary for the price signals sent to demand response providers to be economically efficient.[11]

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[11] Statement of Andy Ott for PJM Interconnection, LLC, Transcript at 20 ("Certainly paying full LMP, LMP is the value in the market of Demand Response, but depending on the retail structure underneath the customer—in some cases, paying full LMP would be fine from the wholesale side. In other cases, it could pay full LMP from the wholesale side but may create unintended consequence because of the retail rate structure underneath."); Statement of Robert Ethier for ISO New England, Transcript at 23 ("And what we found is, paying the full LMP results in negative Net Benefits. Real-time pricing and LMP minus the retail rate results in positive Net Benefits."), 93 ("If you assign the LMP minus G portion back to the load-serving entity that's serving the customer, the fixed retail rate, that actually hedges them perfectly against levels of Demand Response. Interestingly, they actually voted within the New England stakeholder process, to have those costs assigned to them, the LMP minus G cost."); Statement of Michael Robinson for the Midwest Independent Transmission System Operator, Transcript at 159 ("We recognize that if you look behind the curtain that there are avoided retail revenues that the LSE in this particular regime is not indifferent. And so as a service to the LSEs and to the retail—the relevant electric retail regulatory authorities, we offered to back out from the LMP the marginal foregone retail rates that the end-use consumers were avoiding.").

Load-Serving Entities. LSEs generally supported the views of the generators.[12] They expressed con-

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[12] Statement of Stephen Sunderhauf for PEPCO, Transcript at 58 ("We do not believe that a load response program which pays full energy locational marginal price for load reductions at every hour will necessarily result in the optimal level of load response. In general, DR programs should be market-based, and incentives for load response programs above market prices should be limited to extreme conditions, for example, to mitigate high market prices and to provide additional resources when electricity supply is scarce. Paying full LMP for load reductions at any hour and without respect to wholesale energy market conditions is likely to result in excess incentives for DR, since the total compensation to DR participants could exceed the market determined value of electricity."); Statement of Carl Silsbee for Southern California Edison, Transcript at 161-162 ("We support the proposed rule's conclusion that Demand Response compensation in wholesale markets should be at the LMP. This is consistent with how PDR is designed. While we agree with those who recommend an adjustment for retail bill savings—the so-called "minus G" adjustment—we believe that this is properly the jurisdiction of state regulatory agencies, and that FERC should neither require nor enjoin the use of a Minus G adjustment at retail."); Statement of Tim Brennan for National Grid, Transcript at 164 (" . . . National Grid supports full LMP compensation in certain limited hours when Net Benefits to the market outweigh the costs, and for all other hours supports compensation at the LMP-minus-generation costs they avoid in the retail rates by foregoing consumption, otherwise known as LMP-minus-G."); Statement of Megan Wisersky for Midwest Transmission Dependent Utilities, Transcript at 177 ("So from our point of view, paying full LMP instead of doing something like LMP Minus G, we're talking about subsidy, in our opinion. And if there is a subsidy, none of the Cost Allocation proposals will work. They all have problems because it doesn't deal with the "missing money" problem appropriately. And, as mentioned in earlier panelists, we

cern that LSEs might under-collect their retail revenues if the full LMP was mandated to be charged in all hours.[13]

State Public Utility Commissions. State public utility commissions ("PUCs") expressed concern about

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believe that actually will retard Demand Response development, particularly with utilities such as MG&E.").

[13] Megan Wisersky, Transcript at 179 ("So as long as you have this 'missing money,' if you're going to socialize or uplift this cost, the allocation process just does not work properly. One of the things that at MG&E we kind of, we jokingly say is 'load always pays.' I don't care how you—if you charge transmission owners or such, somehow, you know, all that money gets funneled back to load. So that's where it's very important to consider the compensation in DR and how it affects utilities and the customers of utilities such as MG&E. Because—and this may sound a little vulgar, but it in our mind is just basically wrong to stick the G costs to the LSE."); Carl Silsbee, Transcript at 193-194 ("Let's say that we have a 500 kW customer, and that customer has contracted with a Demand Response provider to supply 400 kW of load reduction, and bids it, and it's called. Under the way the PDR works in California, the customer would reduce load to 100 kW, but we as the LSE would still pay, or be responsible for 500 kW in wholesale markets. And we're okay with that. We probably had planned and bought power to serve that 500 kW in advance. Where we run into problems is, we'd also planned to get 500 kW of payment at retail from the customer. And now the customer is only seeing meter spin of 100 kW. So there's 400 kW of retail payment that we didn't get. And that's why we're looking to the state to find some way to compensate us for the loss of compensation at retail, the Minus G.").

payment of the full LMP in all hours.[14] They also noted the lack of coordination between retail electric prices and the wholesale prices that would be paid for demand response if the full LMP was the RTO standard, and the potential for cross-subsidization that could result.[15]

Consumer Advocates. Consumer advocates seemed to be split on the issues raised by the NOPR, with some supporting an offset to LMP under certain circumstances.[16] Others supported the payment of

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[14] *See, e.g.*, Statement of John Keene for the New England Conference of Public Utility Commissioners, Transcript at 12 ("NECPUC agrees with compensating DR at Full LMP for the reasons we stated in our initial comments, but allowing such compensation in all hours may unreasonably increase costs to consumers in certain circumstances.").

[15] Statement of John Keene, Transcript at 17 ("We agree with Professor Kahn that retail rates should not be permitted to undermine efficient wholesale rates. However, nor should wholesale rate mechanisms—at least those designed in part to compensate for inefficient retail designs, such as procuring demand as supply—be allowed to hinder the introduction of dynamic pricing mechanisms at the retail level."); Statement of Commissioner Paul Centolella of the Ohio Public Utilities Commission at 143 ("First, the purchase of Demand Response resources at full LMP effectively discriminates in favor of RTO program participants over consumers responding to retail prices, and will displace price-responsive demand that could have curtailed for less than the total incentive received by RTO program participants.").

[16] Statement of Saul Rigberg for the New York State Consumer Protection Board, Transcript at 32 ("So we largely agree with the

full LMP to wholesale demand responders, on the theory that lower-priced demand response would displace higher-priced generation, thus leading to lower LMPs than would otherwise result.[17] While APPA does not necessarily agree with this logic, it understands the desire of consumer advocates to find some way of disciplining LMPs, because of the current flaws in RTO-run centralized markets.

It is not often that APPA finds itself in more agreement with generation-side industry analysts than consumer-side advocates. But this is one of those times. APPA opposes a blanket rule requiring the payment of the full LMP to wholesale demand response providers in all hours, for two primary reasons.

First, provision of retail electric service is not free. As not-for-profit LSEs providing bundled retail electric service pursuant to a service obligation to serve all customers in their service territories, APPA members located in RTO regions incur substantial costs to provide such service. In addition to maintaining and

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comments of Mr. Keene regarding the need for paying full LMP when there's a net benefit to consumers.").

[17] Statement of Sonny Popowsky for the Pennsylvania Office of Consumer Advocate, Transcript at 152 ("Now in my view the current FERC NOPR represents an important and potential valuable effort to prevent excessive energy prices in wholesale markets such as PJM. To the extent that Demand Response programs can in fact displace higher cost generating units in the PJM dispatch, then the impact on the cost to consumers who are purchasing power through the PJM energy markets can be profound.").

upgrading distribution infrastructure, they must procure power supply (either owned or contracted for) and must arrange for transmission of that power supply to their distribution systems via the RTO. They have a portfolio of generation resources (both owned and contracted for), and are increasingly incorporating demand-side resources into their portfolios, expending considerable dollars to do so. They must estimate the demand on their distribution systems in advance and purchase/schedule generation and transmission services accordingly. When retail customers on their systems decide in near real time to reduce their energy-related demand so they can be paid for demand response, such decisions can have adverse financial impacts on their LSEs, especially if these reductions are not coordinated carefully with those LSEs in advance.

Moreover, over time such demand response activities can change the load shape of the LSEs, and require reassessment of their power supply portfolios. But if the LSE is still required to stand by to provide retail electric service for the full load of such customers at all times, because the industrials/large commercial customers engaging in wholesale demand response activities have no *obligation* to reduce energy demand, but only the option to do so when it is in each customer's economic interests, this puts the LSE in a bind. How does it account for such demand response activi-

ties in its power supply planning?[18] Does it permanently reduce its commitments and endanger its ability to provide service at full demand, or does it maintain its ability to serve the full demand? And if it does maintain the full ability, who pays for the maintenance of this ability?

Moreover, LSEs are investing substantial dollars in their own demand response programs. If, however, the largest and most lucrative customers with the most demand response potential choose not to participate in these programs, but instead to sell their demand response directly to the RTO's wholesale market, these programs could be adversely impacted. The investments made, however, still need to be recovered. From what customers can they be recovered?

The industrial/large commercial customer representatives appearing at the Technical Conference seemed to be under the impression that simply by virtue of being retail electric customers of an LSE, they have paid all relevant costs to their LSEs, and hence should be free to participate (or not participate) in wholesale demand response activities as the spirit

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[18] Megan Wisersky, Transcript at 202 ("And how we plan, or how we do our long-term planning, is I did mention that our utility-based programs are nonfirm load that we don't carry reserves. So there is a question about what happens to that if you cut that Demand Response loose from the LSE in this type of regulated state, what happens to it?").

moves them.[19] But as explained above, this is not the case (at least for LSEs providing bundled retail electric service pursuant to a long-term service obligation), especially in the absence of full "decoupling" of retail electric rates.[20] Hence, APPA shares the concerns of Commissioner Moeller (Transcript at 234), who noted his concern about cross-subsidization of retail electric

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[19] Angela Beehler, Transcript at 230-231 ("We appreciate the power our utilities supply to us, and it's very important to us. But on a side note, when I choose to go to Demand Response and supply that service and that sacrifice to do that, I deliver GHG free curtailment, which is lower than—it's free. It's free curtailment."); Jay Brew, Transcript at 201-202 ("Remember, there's never a load factor obligation. There's no rate where a customer is obliged to acquire certain capacities. Recovery of fixed costs is usually addressed through capacity charges or demand ratchets at the state level. But what the customer's load factor is, or whether they go up or down is, I mean, is entirely separate from the issue of fully recovering the cost of the DR compensation program."); Don Sipe, Transcript at 87 ("Generators are trying to convert the obligation to serve into a right to compel service, and that is incorrect. They don't need to be paid twice for that option, and it's not overpayment when a consumer who has already paid for it, through the regulatory bargain, releases it."). In fact, the ability of industrial customers to "swing" on their retail suppliers is not a cost-free activity, and over time will adversely impact the long-term ability of LSEs to plan their power supply portfolios. This is especially so when utilities recover some portion of their costs in variable rates.

[20] Ironically, industrial customers have been among the most vociferous critics of decoupling. *See, e.g.*, ELCON's January 2007 Policy Brief on Revenue Decoupling, available at http://www.elcon.org/Documents/Publications/3-1RevenueDecoupling.PDF.

customers participating in wholesale demand response by those retail customers who do not:

> I think without dynamic pricing we have the serious potential of residential consumers subsidizing wholesale consumers, and that worries me greatly. And I think the key is shifting demand, and we've got to do it through dynamic pricing. If we do this wrong, we will have the opposite effect.

Second, payment of the full LMP may result in perverse economic incentives that no one has yet anticipated. APPA is concerned that by paying wholesale demand response providers the full LMP in all hours, yet another constituency will become invested in the LMP paradigm, with a vested interest in seeing clearing prices increase to maximize their profits. This is already the case with the generator community. APPA presumes that generators oppose paying wholesale demand response providers the full LMP because this may have the potential to result in lower LMPs (the same reason why some consumer advocates support payment of the full LMP). But APPA fears another, more ominous result—just as generators have over time learned to play the LMP auction rules to increase overall price levels while staying just within the prescribed behavioral lines (thus avoiding mitigation of their bids by RTO market monitors), wholesale demand response suppliers could over time learn how to play the very same game, engaging in auction strategies that maximize their profits (as well as those of the generators). In other words, rather than demand

response serving a disciplining role on clearing prices, the Commission may unintentionally create another constituency with perverse economic incentives to keep clearing price levels high. Such a result would take the doctrine of unintended consequences to a whole new level.

WHEREFORE, as stated in prior comments, APPA respectfully requests that the Commission refrain from promulgating its proposed regulation set out in its NOPR, and instead issue a Notice of Inquiry to explore more fully the potential impacts of payment of the full LMP to wholesale demand response suppliers if it believes that further proceedings in this docket are required.

Respectfully submitted,

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Oct. 13, 2010

UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. RM10-17-000

DEMAND RESPONSE COMPENSATION IN ORGANIZED
WHOLESALE ENERGY MARKETS

Oct. 13, 2010

POST CONFERENCE COMMENTS OF THE ELECTRIC POWER SUPPLY ASSOCIATION

The Electric Power Supply Association ("EPSA")[1] submits these comments pursuant to the Federal Energy Regulatory Commission's ("FERC" or "Commis-

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[1] EPSA is the national trade association representing competitive power suppliers, including generators and marketers. These Suppliers, who account for 40 percent of the installed generating capacity in the United States, provide reliable and competitively priced electricity from environmentally responsible facilities. EPSA seeks to bring the benefits of competition to all power customers. The comments contained in this filing represent the position of EPSA as an organization, but not necessarily the views of any particular member with respect to any issue. EPSA is an active participant in this proceeding. *See* Comments of the Electric Power Supply Association, Docket No. RM10-17-000 (filed May 12, 2010) (the "EPSA Initial Comments"); *also* Reply Comments of the Electric Power Supply Association, Docket No. RM10-17-000 (filed June 30, 2010) (the "EPSA Reply Comments").

sion") August 2, 2010 Supplemental Notice of Proposed Rulemaking and Notice of Technical Conference, which established a date for submittal of post-technical conference comments in the above captioned proceeding.[2] The staff-led technical conference was held on September 13, 2010, with two panels confined to discussions of only the two specific issues raised for comment in the Supplemental NOPR: (1) if the Commission were to adopt a net benefits test for determining when to compensate demand response ("DR") providers the full Locational Marginal Price as proposed, what, if any, requirements should apply to the methods for determining net benefits; and, (2) what, if any, requirements should apply to how the significant costs of the subsidies for DR in the NOPR are allocated among other consumers, who would primarily and disproportionately be residential customers.[3] These are but two of the many questions,

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[2] *Demand Response Compensation in Organized Wholesale Energy Markets*, Supplemental Notice of Proposed Rulemaking and Notice of Technical Conference at P 19, 132 FERC ¶ 61,094 (August 2, 2010) ("Supplemental NOPR"). The Supplemental NOPR follows the Notice of Proposed Rulemaking issued in this proceeding, *Demand Response Compensation in Organized Wholesale Energy Markets*, 75 Fed. Reg. 15,362 (Mar. 29, 2010), 130 FERC ¶ 61,213 (2010) ("NOPR").

[3] *Supplemental Notice of Technical Conference and Notice of Comment Date*, Docket No. RM10-17-000 (August 27, 2010) ("Conference Notice"). The Conference Notice scheduled the technical conference for September 13, 2010 (the "September 13 Technical Conference"), with post-conference comments due on or by October 13, 2010.

issues and concerns raised and documented by a diverse set of stakeholders in this proceeding. However, thus far only these two questions have been subjects for a technical conference and a Supplemental NOPR in this proceeding, leaving a long list of other critical matters as yet unanswered or unaddressed.

EPSA has previously stated its full support for the role properly compensated DR can and should play in wholesale energy markets. The stated premise of the NOPR as discussed at the technical conference and elsewhere is payment of equivalent compensation to DR as is paid for power supply because DR is, or if it is, an equivalent service to that of traditional generation supply.[4] For sake of discussion, EPSA is willing

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[4] Chairman Jon Wellinghoff noted at the beginning of the September 13 technical conference, "[T]he presumption here is that there should be equivalent compensation for equivalent services, and that's where the Commission started here. We started with giving the full LMP to Demand Response for bidding into these markets. And I still believe that's the correct result. It's a presumption. It's a presumption certainly that is subject to being rebutted." *Demand Response Compensation in Organized Wholesale Energy Markets*, Transcript at pp. 7-8, lines 20-25 and 1-2, Docket No. RM10-17-000 (Sept. 13, 2010) ("Transcript") (Chairman Jon Wellinghoff). While Chairman Wellinghoff said the following day in an address to the Alliance to Save Energy that no one at the conference had rebutted the stated presumption, unfortunately doing so was not within the limited agenda of the conference, although EPSA would welcome the opportunity to discuss and rebut the presumption for the extensive reasons outlined here and in other filings in this proceeding. Craig Canno, "Wellinghoff firm on equal treatment for demand, supply-side resources," *Elec-*

to assume, but does not concede, this functional equivalency. However, even with that assumption, a fundamental flaw of the NOPR, not corrected by the Supplemental NOPR, is that it fails to require DR providers to operate under the equivalent regulatory requirements applicable to power suppliers in all relevant markets (energy, capacity and ancillary services) to justify "equivalent" payment in energy markets even if they are functionally equivalent. Absent explicit equivalent regulatory treatment of DR being required by the NOPR, and adjustments as necessary and appropriate to other tariff provisions now applicable to generation (e.g., market mitigation such as the three pivotal supplier test), paying full LMP in all hours to DR as proposed by the NOPR amounts to a decidedly discriminatory, unjustified and unsustainable subsidy that will undermine, not strengthen, the organized wholesale electricity markets within the Commission's jurisdiction. EPSA does not make this assertion lightly. The Commission should be aware of the monumental mistake it would be making if it proceeds to a final rule based on the NOPR without addressing these concerns.

Far from being a carefully crafted comprehensive regulatory proposal that addresses regulatory equiva-

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tric Power Daily (September 15, 2010). See also: Lynn Doan, "Wellinghoff: I'm a 'soldier' fighting in an 'epic' battle for demand response," *SNL* (September 14, 2010); and "Wellinghoff: Epic Battle," *Energy Washington NewsRoom Blog* (September 14, 2010).

lency, economic impact, and other critical issues as identified by EPSA and others in this docket, the NOPR's proposed tariff language as it stands even after the Supplemental NOPR is breathtaking in its brevity:

> Each Commission approved independent system operator or regional transmission organization that has a tariff provision permitting demand response resources to participate as a resource in the energy market by reducing consumption of electric energy from their expected levels in response to price signals must pay to those demand response providers, in all hours, the market price for energy for these reductions.[5]

EPSA respectfully submits that the two narrow questions in the Supplemental NOPR and the constrained discussion at the technical conference barely scratch the surface of the depth and breadth of the inquiry necessary to reach a well-reasoned and factually supportable result in this proceeding. As noted below, certain of these unasked questions implicate broad negative impacts to the electric industry and the U.S. economy as a whole. Nonetheless, EPSA appreciates the opportunity to provide comments on the two issues raised in the Supplemental NOPR before turning to the many outstanding issues not yet fully ad-

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[5] NOPR at p. 31, *see* proposed regulatory text to amend Section 35.28 to add new paragraph (g)(1)(v), "Non-discriminatory open access transmission tariff."

dressed by the Commission and why it is essential that the Commission address them with broader public participation prior to issuing a final rule.

As to the usefulness and type of net benefit tests which may be utilized to determine when to pay full LMP to DR providers, EPSA believes that such a test cannot overcome the problems inherent in the initial DR compensation proposal. Simply developing a test to limit the application of full LMP payments for DR (such as to certain hours) does not avoid overpaying DR and the cascading negative impacts on wholesale electricity markets that will result. The very need to discuss a potential "net benefits test" exposes the foundational flaws in the NOPR.[6]

On the question of how the costs of DR should be allocated, EPSA does not have a proposal or recommendation. As was the case with the discussion at the technical conference of some type of net benefits test, consideration of a cost allocation scheme is necessary only because overpaying DR the full LMP without an offset creates substantial uplift costs that then need to be allocated to other consumers. As EPSA and numerous parties have stated previously in the record of this proceeding, and will not belabor here, use of a DR

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[6] As noted by Ohio Public Utilities Commissioner Paul Centolella at the technical conference, "The Net Benefits test reflects a recognition that paying full LMP may over-compensate Demand Response and increase costs to consumers." Transcript at p. 141, lines 6-12.

payment mechanism that accounts for the avoided cost savings from consuming less electricity from the grid when DR is called upon (so-called "LMP-G" or the market price minus the generation component of the retail electricity rate) properly compensates DR[7] without adding the complexities associated with administering a cost allocation scheme.

EPSA reiterates its desire to be a constructive part of the ongoing dialogue on DR compensation. Rather than being wedded to the payment of full LMP in all hours with only cursory tariff language as proposed in the NOPR, a better course of action is to first inquire as to why the "equivalency" being sought between demand and supply could not be achieved by a straightforward approach based on allowing DR providers to bid into organized wholesale markets (energy, capacity and ancillary services) under the same terms and conditions as those that apply to power suppliers, thereby truly following the "equivalent payment" principle. The Commission has not undertaken that inquiry and should do so before concluding that the NOPR's subsidy approach is a necessary and appropriate payment for DR that is within the Commission's jurisdiction and

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[7] EPSA Reply Comments, fn. 70, citing numerous and diverse initial comments filed in this proceeding which support an offset to LMP in order to achieve an economically efficient and proper price for economic DR. Additionally, William W. Hogan, "Implications for Consumers of the NOPR's Proposal to Pay the LMP for All Demand Response," p. 2, Attachment 1 to the EPSA Initial Comments, Docket No. RM10-17-000, (filed May 12, 2010).

meets the Federal Power Act's test of being just and reasonable and not unduly discriminatory or preferential.

In addition to a full discussion of how DR can and should participate in the organized wholesale energy markets in a truly equivalent manner to generation, there are key issues which call out for a broader examination than has occurred to date. EPSA respectfully suggests that the following questions and issues are among those that need to be addressed by the Commission on the record with opportunities for public comment on the Commission's conclusions as they were not adequately addressed under the terms of the Supplemental NOPR and the technical conference.

(1) On what basis does the Commission claim legal jurisdiction to order the payment of full LMP to DR, particularly in light of the concession by DR providers at the technical conference that they are not actually selling energy into energy markets but providing an ill-defined "service"? This should include on what basis DR providers have a right under the Federal Power Act to just and reasonable compensation in light of the *EnergyConnect* order[8] discussed in more detail in previously filed EPSA comments. This legal analysis should also address whether it is proper for the Commission to use the NOPR to circum-

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[8] 130 FERC ¶ 61,031 (2010) ("EnergyConnect").

vent state jurisdictional retail market design through a federal wholesale pricing mechanism as stated at the technical conference is the aim of the NOPR.[9]

(2) Given the statements at the technical conference noted above on the Commission's desire to use a standardized wholesale payment mechanism to address Commission displeasure with certain state-jurisdictional retail policies, does the NOPR conflict with Congressional intent in requiring the Commission to develop a National Action Plan for Demand Response that limits the Commission's role to collecting and disseminating information on diverse state and regional DR mechanisms without mention of developing a uniform rule for all organized power markets?

(3) The NOPR implies without any factual foundation or analysis that current Commission-approved wholesale rates, market rules and mitigation procedures that apply to generation

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[9] *See*: Remarks of Chairman Wellinghoff, who stated: "I have no assurances as to when the states will put in dynamic retail prices with the controversies that are going on, all the political problems with getting those in place. I think the only way we are going to get this technology in place and we're going to move forward with it is to move forward with it in the wholesale markets." Transcript, p. 234, lines 5-11.

are no longer just and reasonable.[10] Similarly, there is no factual foundation for the NOPR's claim that existing market structures have hindered the development and use of DR in organized markets.[11] As concluding that such existing rates, rules and procedures are no longer just and reasonable is a predicate to justifying the NOPR, does the Administrative Procedure Act require a meaningful opportunity for interested parties to comment on or rebut any evidence the Commission is relying on to reach that conclusion since to date none

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[10] NOPR at P 13: "As we have gained experience with these programs, we are concerned that the current compensation levels ***appear*** to have become unjust and unreasonable. Providers may submit price and quantity bids into the organized wholesale energy markets and the market clears at the marginal resource yet they fail to compensate demand response at levels that reflect the marginal value of the resource being used by the RTO or ISO to balance supply and demand. The current wholesale compensation levels ***may*** therefore be leading to under-investment in demand response resources, resulting in higher, and unjust and unreasonable, prices in the organized electricity markets. To help ensure that wholesale prices in ISOs and RTOs remain just and reasonable, we are proposing to require each ISO and RTO to pay the LMP to demand response providers participating in the organized wholesale energy markets." (Emphasis added.).

[11] NOPR at P 9: "After several years of observing demand response participation in ISO and RTO markets with different, and often evolving, demand response compensation structures, the Commission is ***concerned*** that ***some*** existing, inadequate compensation structures have hindered the development and use of demand response." (Emphasis added.).

has been made public? If so, the failure of the Commission to provide such an opportunity could complicate rather than accelerate achievement of the NOPR's goals by subjecting a flawed final rule to lengthy and successful legal challenges.

(4) How would the NOPR impact clearly FERC-jurisdictional entities that depend on revenues from wholesale energy markets, capacity markets and ancillary services markets to operate existing power plants and build new ones based on market price signals? The one-sided discussion at the technical conference was about avoiding payment to certain types of generation supply sources through artificial suppression of wholesale power prices without any opportunity to discuss how doing so could result in unjust and unreasonable prices for generation suppliers that would negatively impact resource adequacy and thus reliability.

(5) In the same vein, there was a disconnect at the technical conference between the stated desire by some to artificially supplant peaking generation with DR and the Commission's interest in other proceedings in making sure that the very same peaking resources are available

to balance intermittent renewable resources such as wind.[12]

(6) The relationship between wholesale energy markets and capacity markets was not addressed at the technical conference even though it is the aggregation of revenues from all wholesale markets that is intended to ensure adequate compensation for traditional supply resources. If DR resources are to participate on a footing equal to traditional

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[12] See, for example: Transcript, p. 173, lines 9-10, Ms. Angela Beehler of Wal-Mart states: "We decrease the need for some ratepayer funded peaker plants." In contrast, Mr. Stephen Sunderhauf of Pepco Holdings, Inc. states: "[T]he development of DR market standards should be undertaken with explicit examination of the impact of these program standards on the reliability of RTOs." Transcript, p. 57, lines 14-17. Of note, in a thinly disguised attempt to distract from the subsidies that residential consumers would pay to larger entities such as Wal-Mart under the NOPR, Ms. Beehler confused generation plants in vertically-integrated states with the peaking plants in restructured states actually at issue in this proceeding to incorrectly imply "ratepayer" benefits from the NOPR. The description "ratepayer funded" applies to vertically-integrated states not to restructured states. In restructured states the risks placed on ratepayers in vertically-integrated states are largely shifted to suppliers, which is good for consumers including Wal-Mart. In organized wholesale markets the substantial investments necessary for reliability hinge on accurate price signals reflecting supply and demand, not on any one entity's assertion that "some" resources are or are not needed. This is why an explicit detailed examination of the NOPR's impact on reliability is required.

supply resources, this relationship should hold true for them as well.[13] In fact, DR resources currently participate in ISO/RTO capacity markets extensively, though they are not allowed to set the LMP clearing price, and unlike generation are able to do so without bid price caps, offer mitigation, or Peak' Energy Rent deductions (and comparable energy offsets)[14] that apply to generation resources in certain organized markets. Through that difference alone, DR already receives the val-

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[13] As has been noted in numerous initial and reply comments, the NOPR has deemed consideration of the capacity (or other) markets as outside the scope of this proceeding which focuses only on the Day Ahead and Real-Time energy markets. "Apart from these [other ISO/RTO] programs, wholesale customers and qualifying large retail customers may bid demand response directly into the day-ahead and real-time energy markets, certain ancillary service markets and capacity markets. Demand response providers participating as resources in the day-ahead and real-time energy markets are the subject of this proceeding." NOPR at P 7 (citation omitted).

[14] For instance, in ISO New England DR sold as capacity is not required to rebate a Peak Energy Rent (PER) from their capacity payments as do all other capacity sellers. Additionally, DR is able to receive the full capacity clearing price without any PER deduction from the clearing price whether the DR provider reduces its load in an hour or not. This is not comparable to any other capacity seller, including generation, and represents a preferential ability to recover greater fixed costs than other resources in the capacity market. As a result, far from being "equivalent payment for equivalent service," the NOPR treats DR in this circumstance *better* than generation.

ue of certain peak energy margins without any obligation to reduce load in many of those hours. These important revenue streams, as well as those from the emergency and ancillary service markets, should be taken into account in this proceeding if true equivalency is the real objective of the NOPR rather than subsidies that give rise to the net benefits and cost allocation questions in the Supplemental NOPR.[15]

(7) The NOPR's proposed tariff language would pay full LMP to DR in all hours regardless of market and operational conditions. Is there a saturation level of DR inconsistent with reliable grid operations? This is particularly important given the physical and financially

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[15] Additionally, concerns were raised at the technical conference regarding the impact on prices in capacity markets stemming from the suppression of energy prices by subsidized DR resources. Bob Ethier of ISO New England stated, "To the extent that paying these resources, and getting them engaged in the market reduces LMPs, that is going to have carry-on effects into the capacity market. Those effects are easy to describe. For example, generation gets money from both the energy and the capacity markets. To the extent that energy market revenues decrease, they're going to increase the amount that they need to recover from the capacity market before they either enter the market, or before they retire from the market and de-list." Transcript, p. 24, lines 10-19. Despite this independent expert testimony on the unseverable link between capacity and energy markets, as noted the NOPR expressly proposes to change energy market rules while excluding impacts on capacity market revenues and issues.

interconnected nature of the assets within the wholesale markets that would be forced to over-compensate DR, and thus incentivize more DR than economically efficient, which could produce excessive amounts of DR. While the saturation issue is being discussed within individual organized markets,[16] the NOPR is proceeding without benefit of those discussions and without any requirement for organized markets to take steps to avoid saturation.

(8) On the flip side from saturation, is there a fatigue factor that limits the practical willingness of DR resources to participate, particularly with a favorable change in economic conditions as the economy grows making at least some DR less practical, but only after the distorted price signals from the NOPR indicate to traditional supply side resources that they are not necessary? While generation resources take varying amounts of time to be built or come back on line once mothballed or

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[16] For example, PJM stakeholders are considering a range of potential modifications to PJM market rules to address concerns identified in a May 2010 PJM staff study analyzing the level at which demand response ceases to provide the level of system reliability upon which PJM operations relies. The study, "Demand Resource Saturation Analysis," developed by the Resource Adequacy Planning Department may be found on the PJM website at: http://www.pjm.com/~/media/committees-groups/committees/mrc/20100518/20100518-item-05-dr-saturation-report.ashx.

retired, supply is steel in the ground available for decades. By contrast, while DR may be able to respond quickly in some unknown quantities, at the same time those engaging in DR can quickly decide that reducing demand is not in their economic interest, leaving a major resource gap not easily filled once policymakers create uneconomic conditions for generators.

(9) There is nothing in the proposed tariff language to address other practical concerns such as lack of clear measurement and verifiability metrics; how to avoid gaming the baselines against which DR would be measured and paid; requiring the grid operator to be able to dispatch the DR in the same manner as generation for DR to qualify for "equivalent" payment; and differentiating between specific types of DR products (not just any reduction from expected levels as in the NOPR) based on differing technical capabilities such as time of use limitations and response/ramping times.

(10) Would the proposal to institute a standard pricing approach for DR create further disparities or seams between and among the various organized and bilateral markets? Since the NOPR will apply only to those states in an organized market but not to those states outside of an organized market, creating uplift costs and how to allocate them to cover the DR

subsidies in some states but not others, how will the NOPR impact relative electricity rates in states covered by the proposal and those not covered? How will such impacts affect relative economic competitiveness of various states? This was not discussed during the technical conference's panel on cost allocation.

(11) The NOPR is being considered at a time of high unemployment and low economic growth. The NOPR does not distinguish between types of demand reductions in determining what actions by electricity users would qualify for the full payment of LMP in addition to the savings from avoided costs. In fact, by its terms, the proposed tariff language would broadly apply to "reducing consumption of electric energy from their expected levels in response to price signals." The impact of a national policy that rewards and incents inefficient reductions in electricity use that in turn results in lower economic activity should be carefully analyzed and its impacts explicitly considered.

(12) How does the NOPR relate to or impact ongoing stakeholder discussions and FERC proceedings involving DR as mandated by Order No. 719 in MISO and ISO-NE as the NOPR only terminated such discussions in PJM? Given that equivalency of all supply resources broadly defined to include DR is the stated goal of the NOPR, why does the NOPR not

address scarcity pricing for all resources in the organized markets on an equivalent basis?

At this stage, with the array of these and other fundamental questions being raised by a diverse set of stakeholders beyond the power generation sector, but not addressed either in the NOPR, the Supplemental NOPR, or the technical conference, EPSA recommends that the Commission revert this proceeding back to the Notice of Inquiry stage where it should have started to do the basic analysis and actually develop the record necessary to justify a generic final rule on DR compensation. Alternatively, EPSA recommends that the Commission fashion a new proposal that squarely and fully addresses the legal and economic concerns stated by the majority of commenters in this proceeding.[17] As of the September 13 technical conference the record to date does not support moving forward with a final rule predicated on a NOPR that

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[17] A new proposal is not without precedent, for example, see Docket No. RM07-1-000. In that proceeding, the Commission first promulgated a January 2007 NOPR (118 FERC ¶ 61,031) proposing to relax the Standards of Conduct so that certain categories of employees could share information. Upon further consideration and review of the comments in the record, the Commission published a second NOPR in March 2008, which stated: "After giving consideration to these comments and to our own experience in enforcing the Standards, the Commission believes it to be necessary and appropriate to modify the approach proposed in the initial NOPR." (122 FERC ¶ 61,263) It was the second NOPR upon which the final rule, Order No. 717 (125 FERC ¶ 61,064), was based.

ignores serious negative consequences that will follow for organized markets and the economy at large for decades to come.

I. CONCLUSION

WHEREFORE, for the foregoing reasons, EPSA respectfully requests that the Commission consider these comments in determining further action in this proceeding. As discussed in detail herein, the record in this proceeding is insufficient and lacks a sound basis for the Commission to proceed to issuance of a final rule without major modifications. Although numerous comments have been filed by many diverse parties, a Supplemental NOPR has been issued, and a technical conference convened, there remain many unanswered questions and serious concerns regarding the significant impacts sparked by the NOPR.

Consequently, EPSA recommends that the Commission allow for further development of the record through issuance of a NOI or promulgation of a new proposal, either of which should be accompanied by a Commission staff white paper providing the necessary underlying technical and economic analyses to support further consideration of the complex issues surrounding the appropriate compensation of DR resources. EPSA looks forward to continuing this dialogue and working with all interested parties to craft an approach that is truly beneficial to the wholesale electricity markets and the consumers they serve.

Respectfully submitted,

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Oct. 13, 2010

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UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. RM10-17-000

DEMAND RESPONSE COMPENSATION IN ORGANIZED
WHOLESALE ENERGY MARKETS

[Oct. 13, 2010]

COMMENTS OF THE MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.

In accordance with the Federal Energy Regulatory Commission's ("Commission" or "FERC") request for comments in the subject proceeding, the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") respectfully submits the following comments with respect to matters addressed at the Commission's September 13, 2010 technical conference regarding the compensation of demand response ("DR") resources.

I. INTRODUCTION

The Midwest ISO is an unbiased entity charged with the operation and administration of the wholesale electricity markets in thirteen Midwestern states and one Canadian province. In this role, the Midwest ISO is concerned with ensuring that any DR compensation scheme satisfies the Commission's goals and policies regarding

DR while being fair and equitable for all market participants and is consistent with an efficient wholesale market design. The Commission's current proposal to pay DR providers, in all hours, the market price for energy *(i.e.*, full Locational Marginal Price ("LMP")) for reducing their consumption of electricity from expected levels in response to price signals fails to meet this standard and gives rise to significant concerns regarding, *inter alia*, the allocation of costs incurred as a result of DR. Each of these issues is discussed in more detail in Section III, *infra*.

II. BACKGROUND

On March 18, 2010, the Commission issued a Notice of Proposed Rulemaking ("NOPR") addressing how providers of DR should be compensated.[1] In the NOPR, the Commission proposed that Independent System Operators and Regional Transmission Organizations ("ISOs/RTOs") should implement tariff provisions so that DR providers that participate in energy markets by reducing consumption in response to price signals would be paid the hourly market energy price for each MWh of their curtailed energy usage in that hour.

Following the receipt of comments on the NOPR, the Commission, on August 2, 2010, issued a Supplemental Notice of Proposed Rulemaking and Notice of Technical Conference seeking comment on, and convening a tech-

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[1] *See Demand Response Compensation in Organized Wholesale Energy Markets*, 130 FERC ¶ 61,213 (2010) ("NOPR").

nical conference to discuss, whether the Commission should adopt requirements related to two issues raised in the comments on the NOPR.[2] Specifically, the Commission sought input on the following questions: (1) if the Commission were to adopt a Net Benefits Test ("NBT") for determining when to compensate DR providers, what, if any, requirements should apply to the methods for determining net benefits; and (2) what, if any, requirements should apply to how the costs of DR are allocated. The technical conference was held on September 13, 2010.

III. COMMENTS

A. Proposals to Pay Demand Response Providers Full LMP Give Rise to Serious Concerns that Must Be Addressed in the Commission's Final Rule.

As the Midwest ISO has previously explained in this proceeding, proposals to pay DR providers full LMP are economically inefficient and inequitable.[3] Paying full LMP for DR would reduce the economic efficiency of the wholesale energy markets by encouraging DR providers

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[2] *See* Supplemental Notice of Proposed Rulemaking and Notice of Technical Conference, *Demand Response Compensation in Organized Wholesale Energy Markets*, 132 FERC ¶ 61,094 (2010), as supplemented by Supplemental Notice of Technical Conference and Notice of Comment Date, *Demand Response Compensation in Organized Wholesale Energy Markets*, Docket No. RM10-17-000 (issued Aug. 27, 2010).

[3] In the interest of administrative efficiency, the Midwest ISO is not repeating each of its arguments against paying DR providers full LMP herein, but rather, explicitly incorporates its prior comments by reference.

to curtail incremental loads that would be worth more in terms of productivity value than the costs that generators would avoid by not serving those loads. In other words, overcompensating DR will result in an artificial market construct in which LMP is suppressed below the price at which generation resources will voluntarily bid into the energy market. This not only will reduce the economic efficiency of the wholesale market, it will also unfairly shifts the costs resulting from the inefficient curtailment to those retail customers who do not participate in DR (typically small residential and commercial customers).

The Midwest ISO's compensation proposal for DR providers currently before this Commission does set the correct incentives for both generation and demand resources to participate in Midwest ISO markets. While the value of load curtailment provided by DR providers in the market dispatch of the RTO is LMP, just as it is with generation resources, DR providers should be paid LMP minus the applicable Marginal Foregone Retail Rate ("MFRR"). The Midwest ISO proposes to do this in two steps. One, crediting the DR provider with LMP to appropriately recognize the value of the load curtailment to the market. Two, charging the DR provider with the MFRR to recognize the retail costs avoided by the retail customer. LMP minus MFRR plus MFRR (avoided retail costs) equals full LMP. If the DR provider is compensated at full LMP without being charged MFRR, then the DR provider's compensation is LMP+MFRR, hence, overcompensating the load curtailment. Paying DR providers LMP-MFRR will better align the provision of

DR with true economic price signals and will prevent cross-subsidies within the market, leaving each market participant in the same position it would have been in but for the decision to curtail.

Regardless of the compensation levels determined by the Commission for paying DR resources in the market, the Commission must consider and explicitly address the resulting cost allocation and "missing money" problems discussed in Sections III.B and III.C, *infra*.

B. Payments for DR Should Be Allocated to the Load Serving Entity for a Customer.

Applicable legal precedent generally requires that that there be a correlation between the benefits associated with a particular activity and the costs resulting from that activity.[4] Thus, it is not surprising that a large majority of all participants in this proceeding agree that the costs of DR should appropriately be allocated to the market participant(s) receiving the benefits from DR. As discussed herein, the Midwest ISO agrees with this proposition and submits that, as a result, payments made to compensate retail customers for providing DR should appropriately be allocated to the Load Serving Entity ("LSE") serving that customer.

First, LSEs receive a direct benefit from the provision of DR. Retail tariffs typically give customers the right to buy energy at a fixed, predetermined price in any given

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[4] *Democratic Central Committee v. Washington Metropolitan Area Transit Commission*, 485 F.2d 786, 806 (D.C. Cir. 1973).

hour regardless of the costs their LSEs must incur to produce or procure that energy. This is analogous to granting each customer a quantity of "call options" on electric energy where the option "strike price" is determined by the variable energy rates in that customer's retail tariff. When a customer reduces its load in return for payment from a DR provider, the customer effectively sells some of its unexercised call options to the DR provider. The DR provider then sells these options through the ISO/RTO power pool market. The ISO/RTO includes these options as supply offers in its security constrained economic dispatch, which makes the offers available to one or more buyers participating in its day-ahead and/or real-time energy markets.

The wholesale buyer that has the most to gain from any given unexercised call option is the LSE whose retail customer sold that call option, because that LSE will avoid having to buy at LMP the energy underlying the option while losing only the revenues the customer avoids paying under its retail tariff.[5] No other single market participant will gain as much from the call option going unexercised. As a result, under the Commission's tradi-

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[5] LMP is assumed to be higher than the avoided retail tariff rate, otherwise the retail customer would have no incentive to reduce its consumption of energy, under the compensation proposal proposed by the Midwest ISO. Paying full LMP without charging MFRR gives retail customers incentive to reduce consumption under this scenario.

tional burden follows benefit approach, DR costs should most appropriately be allocated to LSEs.

In addition, examining the counterfactual implies payments to DR should be allocated to LSEs. If the load curtailment did not occur, the LSE as the wholesale buyer would have to pay LMP for the energy consumed by the retail customer who chose not to drop load.

Furthermore, as explained by Dr. Roy J. Shanker at the technical conference in this proceeding, LSEs often reap the full benefit of the "portfolio" effect that results if DR providers are overcompensated.[6] As previously discussed, paying DR providers full LMP overcompensates retail customers for providing DR. As a result, more retail customers are incented to curtail their consumption, ultimately reducing prices in the wholesale market. Notwithstanding the foregoing, however, the benefit of the reduced prices in the wholesale market may not be passed through to consumers. For example, if a retail customer is hedged through forward contracts or other mechanisms, then it will not itself realize a benefit from reduced LMP in the energy market. Rather, the LSE would retain the entire benefit resulting from the reduced consumption. For this reason as well, allocating DR costs to the LSEs is the most appropriate approach.

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[6] *See, e.g.*, Transcript of Technical Conference, *Demand Response Compensation in Organized Wholesale Energy Markets*, Docket No. RM10-17-000 at 69:9-73:1 (issued Sept. 9, 2010).

Additionally, if LSEs are not allocated the costs associated with DR, they may incur a windfall as DR effectively shifts load from high peak hours (in which LSEs often lose money) to low peak hours (when LSEs may over-recover their costs). Retail rates under a fixed tariff are designed to allow the LSE to recover its costs based on the average cost of the wholesale energy market. During high peak hours (when LMP is high) the LSE may lose money in comparison to the fixed retail rate paid by its retail customers. However, the under-recovery experienced by the LSE in high peak hours is expected to be counter-balanced by an over-recovery during low peak hours.

For example, if LMP during high peak hours is $300/MWh and the fixed retail rate paid by the retail customers is $200/MWh, the LSE must spend $300/MWh to recover $200/MWh under its fixed rate tariff. Thus, under this example, the LSE will experience a *loss* of approximately $100/MWh. Now let us assume that during low peak hours LMP is $100/MWh. Because the fixed rate paid by the retail customer does not change in relation to LMP, the retail customer will still pay $200/MWh to procure energy. Under this scenario, the LSE will spend only $100/MWh to recover $200/MWh under the fixed rate tariff. Thus, in low peak hours, the LSE experiences a *gain* of approximately $100/MWh.

In a typical wholesale environment, the under-recoveries experienced by a LSE during high peak hours are counter-balanced by the over-recoveries it experienc-

es during low peak hours. However, if retail consumers incented by the over-payment of DR decide to forego consumption during high peak hours in order to obtain the highest possible DR payments, there may be a shift in demand from high peak hours to low peak hours. As a result, the LSE will experience a net gain more often than it experiences a net loss, resulting in a windfall to the LSE. Allocating DR costs to the LSE will help counter-act this effect.

Additionally, if LSEs are not allocated the costs associated with DR, the costs have to be recovered elsewhere because the RTO is revenue-neutral. Some participants in this proceeding have advocated uplifts to various market participants as a cost recovery mechanism. Uplifts by definition are inefficient forms of cost recovery. Market prices should reflect both the marginal cost to serve the next MW of load and the marginal benefit of consuming that next MW of load. However, the market price does not capture uplift charges. RTOs have been diligently working to reduce side payments (uplifts) to offer competitive wholesale markets and this form of cost allocation would move the RTOs in the opposite direction.

Allocating DR costs to LSEs is also the most appropriate choice because LSEs (unlike other market participants) have the ability to mitigate/recover some of those costs. For example, an ISO's/RTO's settlement system will typically "reconstitute" the LSE's hourly loads by adding back the MWh of load reductions and debiting the LSE for the reconstituted loads at the prevailing LMP.

This process ensures that retail customers selling DR and receiving payment through the wholesale electricity markets also pay for electricity services received through the wholesale electricity market as consumers. Thus, LSEs are able to avoid some of the losses associated with DR that might be incurred if the DR costs were allocated to other market participants. Moreover, the practice of load reconstitution essentially indemnifies LSEs from charges for Real-Time load deviations from their Day-Ahead positions that were solely caused by the DR provided by their retail customers, rather than by any actions of the LSEs.

Allocating the costs associated with DR to the LSEs also prevents the problem of paying twice for the same energy. LSEs generally procure most of their load obligation in the Day-Ahead Market. Thus, if the LSE is not charged for DR through the reconstitution of its load, then the energy would essentially be paid for twice. The energy (load curtailment) is paid once when the DR provider is compensated, and again when the LSE sells the foregone energy into the real-time market. Allocating the costs associated with DR to the LSE eliminates this problem, which is a significant market inefficiency.

In light of the foregoing, the Midwest ISO believes that allocating the costs of DR to LSEs is the correct approach and thus should be adopted by the Commission in its final rule in this proceeding.

C. The Commission Must Address an Additional "Missing Money" Problem.

Although the Midwest ISO believes that LSEs are best suited to bear the costs associated with DR, as discussed in Section III.B, *supra*, the Commission must still address an additional "missing money" problem.[7] The missing money problem arises because, as discussed herein, paying a DR provider full LMP overcompensates DR providers by paying more than the value of the energy being curtailed.

The Midwest ISO believes that if DR providers are paid the full hourly LMP for their load reductions, then adjustments to account for this additional missing money should be left to the Relevant Electric Retail Regulatory Authority ("RERRA") to implement at the retail level. This approach obviates the need for uplifting energy market prices and avoids cross-subsidies among LSEs.

Alternatively, the missing money could be recovered through an uplift to energy prices.[8] Although all LSEs

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[7] The first "missing money" problem is discussed in the Midwest ISO's October 2, 2009 ARC filing before this Commission. When a DR provider drops load it does not inject electricity into the grid. Hence, in order for the RTO to meet the energy balance, it must still move generation resources up. While these dispatch orders may be least cost, it does introduce a revenue inadequacy problem for the RTO that must be addressed.

[8] The amount allocated through an uplift charge should not exceed the avoided MFRR because doing so will produce windfall profits for the LSEs whose retail customers provided DR at the expense of the other LSEs and their customers.

would benefit if the DR reduces market energy prices by more than the magnitude of the needed uplift, the market energy price reduction will not always exceed the uplift charge. Thus, under some circumstances, the benefit resulting from DR may be completely eliminated as a result of the uplift charge. As a result, the Midwest ISO does not advocate this approach. In addition, any costs recovered through uplifts and not the market clearing prices introduces inefficiencies into the market.

Accordingly, the Midwest ISO urges the Commission to explicitly find that any adjustments necessary to account for missing money should be left to the discretion of the RERRA rather than imposed by the Commission.

D. The Midwest ISO Does Not Support the Adoption of a Net Benefits Test. However, if the Commission Does Adopt Such a Test, It Must Be Based Upon Sound Economic Principles.

The Midwest ISO does not support the adoption of a NBT to determine when to compensate DR providers. Such a test is both unnecessary in a competitive wholesale market and the very antithesis of one. In fact, a NBT may distort the decision of when to procure DR. In a competitive wholesale market, consumers will forego consuming electricity when it is more economically efficient for them to save the cost of consuming electricity than to consume electricity *(i.e.,* when the LMP is greater than the value of the energy being curtailed to the DR provider). Thus, if compensation for a DR resource accurately reflects the value of that resource *(e.g.,* because the com-

pensation reflects competitive market pressures), there is no need for a NBT. DR that is cost-beneficial will be procured and DR that is not cost-beneficial will not be procured.

In contrast, utilization of NBT may distort the decision of when to procure DR. Specifically, under a NBT, the decision to procure DR would be made not when it is efficient for the consumer to forego consuming electricity, but when the price suppression effect of DR exceeds the cost, as determined by the market administrator and not the consumer. As a result, the DR resource may be paid more than is necessary to induce the resource to stop consuming in order to achieve net benefits for load. Such a result is both unnecessary and inefficient.

Moreover, creating, implementing and administering a NBT would impose a significant burden upon the ISOs/RTOs and their respective market participants, while providing little, if any, additional value. To begin, DR is effectively a non-action. A DR provider is compensated not for its provision of a product, but for its willingness to forego consuming a product. While one can reasonably presume that a causal connection exists between demand and price and that as a result, prices will fall in relation to reduced demand, identifying what the market price would have been *but for* the reduced demand is an inherently difficult proposition and one that is virtually impossible to achieve with the degree of accuracy needed for a useful NBT.

Further, even if one could accurately identify the monetary benefit of DR, "identifying the[ ] specific beneficiaries [of DR in a specific period) is nearly impossible in practice."[9] As explained by Andrew L. Ott, Senior Vice President, Markets for PJM Interconnection, L.L.C., "it is not practical to rerun market results with and without demand resources with sufficient granularity to accurately identify specific beneficiaries for specific hours."[10] Moreover, not all wholesale customers will directly benefit from a reduction in LMP. For example, wholesale customers that utilize hedging tools through forward contracts or other mechanisms may not actually realize a benefit from reduced LMP in the energy market. However, there is no practical way to identify the particular types of hedging mechanisms that are being utilized by a particular consumer on a particular day or hour. Accordingly, it would be exceedingly difficult and cost prohibitive to determine the actual beneficiaries of DR with any degree of accuracy.

Given the foregoing, the Midwest ISO opposes the use of a NBT to determine when to compensate DR. However, if the Commission disagrees with the Midwest ISO's position and decides to impose a NBT, the NBT must be based upon sound economic principles. Any NBT im-

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[9] *See, e.g.*, Statement of Andrew L. Ott for the Panel Discussion at the Commission's Technical Conference, *Demand Response Compensation in Organized Wholesale Energy Markets*, Docket No. RMJ10-17-000 at 2 (filed Sept. 13, 2010).

[10] *Id.*

posed by the Commission must, *inter alia*, reflect properly specified costs and benefits, in order to ensure that the test is uniformly and objectively applied and is not subject to manipulation.

Thus, any NBT imposed by the Commission should consider the following benefits, each of which should be quantified for each hour in which LMP exceeds the highest MFRR of the retail customers offering economic DR through an Aggregator of Retail Customers ("ARC"): (i) savings in generation costs; (ii) avoided payments for the curtailed load; (iii) reductions in payments for energy purchases resulting from lower market price (including any uplift applied to recover DR payments); (iv) payments to retail customers providing DR; and (v) increases in consumers' surplus due to increased consumption in response to lower market price. The following costs should also be quantified for each hour in which LMP exceeds the highest MFRR and reflected in any NBT: (i) the consumers' surplus lost by retail customers providing the DR; and (ii) the reduction in producers' surplus due to lower market price.

Accordingly, the Midwest ISO respectfully submits the following NBT for the Commission's consideration:

Five distinct groups of market participants gain benefits or incur costs as a result of the DR delivered in each hour.[11] These groups are (i) retail customers providing

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[11] The ISO/RTO is revenue-neutral and thus all costs associated with DR will be passed through to the market participants.

the DR; (ii) retail customers not providing DR; (iii) ARCs; (iv) LSEs; and (v) Power Suppliers *(i.e.*, Generators and Power Marketers). Each of these five groups of market participants experiences unique benefits and costs as a result of DR. These benefits and costs are summarized in Table 1 below:

TABLE 1
COMPREHENSIVE LIST OF BENEFITS AND COSTS OF DR BY TYPE OF MARKET PARTICIPANT

Type of Market Participant	Benefits of DR	Costs of DR
Retail customers providing DR	1. Direct payments from the ARC in exchange for load reductions; 2. Reduced payments for energy through their retail tariff; and 3. Reduced payments for their remaining energy consumption due to lower wholesale market prices (but only if they are on LMP-based retail tariffs)	1. Lost consumers' surplus from forgone electricity consumption; and 2. Direct costs of implementing the load reductions (e.g., control costs, BTMG generation costs, etc.)
Retail customers not providing DR	1. Lower wholesale market prices (but only if they are on LMP-based retail tariffs)[12]	None
ARCs	1. Compensation for DR received from the ISO/RTO	1. Cost of paying retail customers for DR; and 2. Other costs of program administration
LSEs	1. Avoided cost of acquiring energy at LMP for retail customers providing DR that are on fixed-rate tariffs;[13] and 2. Reduced payments for remaining load due to lower wholesale market prices (if energy is purchased from the spot market, *i.e.*, not purchased through fixed-price contracts or otherwise hedged)	1. Cost of reimbursing the ISO/RTO for payments made to ARCs for DR; and 2. Lost retail revenues associated with customers providing DR (only those LSEs serving customers that provided DR)

Type of Market Participant	Benefits of DR	Costs of DR
Power Suppliers	1. Avoided cost of supplying energy conserved through DR	1. Lost revenues from customers on fixed-rate tariffs that provided DR; 2. Lost incremental revenues on the residual energy supplied to retail customers on LMP-based tariffs due to the lower wholesale market prices to the extent they are exposed to wholesale spot market prices

As is shown by the foregoing table, many of the benefits and costs represent transfer payments between various market participants. Thus, these benefits and costs effectively cancel each other out. For example, the benefit received by retail customers providing DR in the form of reduced payments for energy through their retail tariffs is canceled out by the equal and opposite cost incurred by ARCs as a result of paying retail customers for the DR they delivered. This relationship exists with respect to each of the following benefits and costs:

- Retail Customer Providing DR Benefit 1 and ARC Cost 1;
- Retail Customer Providing DR Benefit 2 and LSE Cost 2;
- Retail Customer Providing DR Benefit 3 and Power Suppliers Cost 2 (partial);
- Retail Customer Not Providing DR Benefit 1 and Power Suppliers Cost 2 (partial);
- ARC Benefit 1 and LSE Cost 1;

- LSE Benefit 1 and Power Suppliers Cost 1; and
- LSE Benefit 2 and Power Suppliers Cost 2 (partial[12]).

Netting out the offsetting costs and benefits as described herein leaves the following relationship: Hourly Net Benefit = Power Supplier Benefit 1-Retail Customer Providing DR Cost 1—Retail Customer Providing DR Cost 2-ARC Cost 2. Stated differently, the Hourly Net Benefit equals the Power Suppliers' production cost savings minus the DR providers' lost consumers' surplus minus the DR providers' implementation costs minus the ARCs' administration costs.

Because the NBT described herein considers the actual quantifiable benefits and costs of DR, rather than simply assuming that the NBT will be satisfied whenever the LMP is reduced by even a *de minimus* amount, negative net benefits *(i.e.*, losses) may be produced in some hours, indicating that DR should not be compensated in those hours. Such a result will better align compensation of DR to actual, quantifiable benefits received, and may help mitigate the cross-subsidization issue created as a result of overcompensating DR by ensuring that such compensation is paid only when DR truly benefits the market. In addition, this NBT will demonstrate that customers with LMP-based retail tariffs will always pro-

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[12] The three components of Power Suppliers Cost 2 add to the total revenues lost by Power Suppliers due to the lower wholesale market prices produced by DR.

duce negative Net Benefits *(i.e.,* losses) and thus, should not participate in any DR program. However, even with this safeguard in place, the Net Benefits produced by paying DR providers a price equal to LMP with no offset for customers' avoided MFRR payments, will always be less than if the DR providers were compensated at LMP-MFRR.

Alternatively, the NBT could be separately applied to subsets of retail customers whose MFRRs are similar, and only compensate those customers whose DR produces positive net benefits. Customers with low MFRRs produce the largest net benefits while those with high MFRRs *(e.g.,* those with LMP-based rates) produce the lowest net benefits (and potentially even losses). This approach could help alleviate some of the missing money problem by compensating primarily those DR providers who have the smallest MFRR component *(i.e.,* the smallest amount of missing money).

Although the foregoing proposal requires extremely complex, and costly, data inputs regarding the retail tariffs of the individual retail customers offering to provide DR, the Midwest ISO believes it is nevertheless superior to a NBT that focuses only on a market-wide reduction in LMP, no matter how *de minimus.* Accordingly, if the Commission ultimately chooses to impose a NBT, the NBT must be based upon sound economic principles and reflect properly specified costs and benefits. Notably, the NBT described above does not include the significant

costs that the RTO would incur to develop and continually support the NBT.

IV. CONCLUSION

The Midwest ISO respectfully submits these comments on the subject NOPR and technical conference to assist the Commission in further refining its approach to DR compensation.

Respectfully submitted,

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Oct. 13, 2010

UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. RM10-17-000

DEMAND RESPONSE COMPENSATION IN ORGANIZED
WHOLESALE ENERGY MARKETS

Apr. 14, 2011

JOINT REQUEST FOR REHEARING OF THE ELECTRIC POWER SUPPLY ASSOCIATION, THE AMERICAN PUBLIC POWER ASSOCIATION, THE ELECTRIC POWER GENERATION ASSOCIATION AND THE NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION

Pursuant to Section 313(a) of the Federal Power Act ("FPA")[1] and Rule 713 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission (the "Commission"),[2] the Electric Power Supply Association ("EPSA"),[3] the American Public

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[1] 16 U.S.C. § 825*l*(a) (2006).

[2] 18 C.F.R. § 385.713 (2010).

[3] EPSA is the national trade association representing competitive power suppliers, including generators and marketers. Competitive suppliers, which, collectively, account for 40 percent of the installed generating capacity in the United States, provide reliable and competitively priced electricity from environmentally respon-

Power Association ("APPA"),[4] the Electric Power Generation Association ("EPGA")[5] and the National Rural Electric Cooperative Association ("NRECA")[6] ("Joint

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sible facilities. EPSA seeks to bring the benefits of competition to all power customers. The comments contained in this filing represent the position of EPSA as an organization, but not necessarily the views of any particular member with respect to any issue.

[4] APPA is the national service organization representing the interests of not-for-profit, publicly owned electric utilities throughout the United States. More than 2,000 public power systems provide over 15 percent of all kilowatt-hour sales to ultimate customers, and do business in every State except Hawaii. Public power systems own almost 10 percent of the nation's electric generating capacity, and about eight percent of the nation's higher voltage lines (138 kV or greater).

[5] EPGA is a regional trade association of electric generating companies that supply wholesale electric power in Pennsylvania and surrounding States. Collectively, EPGA member companies own and operate more than 145,000 megawatts of electric generating capacity, approximately half of which is located in the mid-Atlantic region. The comments contained in this filing represent the position of EPGA as an organization, but not necessarily the views of any particular member with respect to any issue.

[6] NRECA is the national service organization for more than 900 not-for-profit rural electric utilities that provide electric energy to approximately 42 million consumers in 47 States or 12 percent of the nation's population. Kilowatt-hour sales by rural electric cooperatives account for approximately 11 percent of all electric energy sold in the United States. NRECA members generate approximately 50 percent of the electric energy they sell and purchase the remaining 50 percent from non-NRECA members. The vast majority of NRECA members are not-for profit, consumer-owned cooperatives. NRECA's members also include approximately 66 generation and transmission ("G&T") cooperatives,

Petitioners") respectfully request rehearing of the final rule on demand response ("DR") compensation in organized wholesale energy markets issued on March 15, 2011 in the above-captioned proceeding.[7]

The members of this admittedly unusual coalition —which includes entities, such as EPSA and APPA, that do not often find themselves on the same side in Commission proceedings—are united by their grave concerns that the Commission has disregarded essential and fundamental statutory limits on the proper exercise of its jurisdiction. Accordingly, although certain of Joint Petitioners will be filing their own separate requests for rehearing raising other concerns and objections to the Commission's Final Rule, Joint Petitioners are making this joint submission to focus on the Final Rule's clear jurisdictional defects. Joint Petitioners are not opposed to, and, indeed, fully support, participation by diverse resources, including DR resources, in wholesale energy markets administered by independent system operators ("ISO") and regional transmission organizations ("RTO"). Joint Petition-

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which generate and transmit power to 668 of the 846 distribution cooperatives. The G&Ts are owned by the distribution cooperatives they serve. Remaining distribution cooperatives receive power directly from other generation sources within the electric utility sector. Both distribution and G&T cooperatives were formed to provide reliable electric service to their owner-members at the lowest reasonable cost.

[7] *Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, FERC Stats. & Regs. ¶ 31,322 (2011) (the "Final Rule").

ers also share the Commission's objective that barriers to DR participation in those markets (if any) be appropriately addressed. But the Commission must do more than pay lip service to the "confines of [its] statutory authority."[8] The Commission may not regulate DR compensation as contemplated by the Final Rule, because it would have the Commission setting rates for non-jurisdictional, retail non-purchases that fall well outside the Commission's delegated authority.[9]

I.

STATEMENT OF ISSUES AND SPECIFICATION OF ERRORS

In accordance with Rules 713(c)(1) and 713(c)(2) of the Commission's Rules of Practice and Procedure,[10] Joint Petitioners hereby specify each alleged error in the Final Rule and list each issue on which they seek rehearing of the Final Rule, providing representative precedent in support of their positions:

1. The Commission lacks authority under Section 205 or 206 of the FPA to set rates, either directly or indirectly, for DR compensation because DR is a non-jurisdictional, retail non-purchase over which Commission has no jurisdiction under Section 201(b) of the FPA. *See, e.g.*, 16 U.S.C. §§ 824, 824d, 824e (2006); 18

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[8] *Id.* at P 115.

[9] Final Rule, FERC Stats. & Regs. ¶ 31,322 at P 115.

[10] 18 C.F.R. § 385.713(c)(2) (2010).

C.F.R. § 35.28(b)(5) (2009); *EnergyConnect, Inc.*, 130 FERC ¶ 61,031 (2010) ("*EnergyConnect*"); *Bonneville Power Admin. v. FERC*, 422 F.3d 908 (2005)("BPA").

2. The Commission's determination that it has authority over DR compensation as a practice "affecting" jurisdictional rates is improper and contrary to law. There is an insufficient nexus between DR compensation practices and jurisdictional rates to justify an exercise of the Commission's "affecting" jurisdiction, and the Commission may not accomplish indirectly what it is prohibited from accomplishing directly. *See, e.g.*, 16 U.S.C. § 824e (2006); *Richmond Power & Light v. FERC*, 574 F.2d 610 (D.C. Cir. 1978) ("*Richmond*").

3. The Commission's determination that it has authority over DR compensation, a retail non-purchase, is arbitrary and capricious because it rests on an improper and unreasonable interpretation of its statutory authority under the FPA as extending into areas traditionally regulated by States, even though Congress has given no indication (and certainly no clear statement) that it intended to grant the Commission such far-reaching authority. *See, e.g., American Bar Ass'n v. Federal Trade Comm'n*, 430 F.3d 457, 471-472 (D.C. Cir. 2005) ("*ABA*").

4. The Commission's determination that it has authority over DR compensation is not supported

by substantial evidence. *See, e.g.*, 5 U.S.C. § 706(2)(E) (2006); *Ill. Commerce Comm'n v. FERC*, 576 F.3d 470, 477 (7th Cir. 2009) ("ICC").

5. The Final Rule rests on an indefensible and unreasonable interpretation of Section 1252(f) of the Energy Policy Act of 2005 ("EPAct 2005"), Pub. L. No. 109-58, 119 Stat. 594, 965 (2005), as supporting the Commission's assertion of jurisdiction to regulate DR compensation. *See, e.g.*, EPAct 2005, § 1252(f); *Comcast Corp. v. FCC*, 600 F.3d 642, 654 (D.C. Cir. 2010) ("*Comcast*").

6. The Final Rule is arbitrary and capricious and contrary to law because it fails to address serious objections to the Commission's exercise of jurisdiction over DR compensation, and it does not draw a rational connection between the Commission's exercise of jurisdiction and the indisputable facts. *See, e.g., Motor Vehicle Mfrs. Ass'n of the U.S. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) ("*State Farm*"); *Moraine Pipeline Co. v. FERC*, 906 F.2d 5 (D.C. Cir. 1990) ("*Moraine Pipeline*"); *Canadian Ass'n of Petroleum Producers v. FERC*, 254 F.3d 289 (D.C. Cir. 2001) ("*CAPP*").

II.

BACKGROUND

In the Final Rule, the Commission adopts the proposal set forth in its March 18, 2010 notice of proposed rulemaking[11] to require ISOs and RTOs to pay DR resources the full locational marginal price ("LMP") for energy, provided that (1) the DR resource "has the capability to balance supply and demand as an alternative to a generation resource;"[12] and (2) "dispatch of that [DR] resource is cost-effective as determined by the net benefits test."[13] In a cursory response to challenges to its jurisdiction to set rates for DR compensation, the Final Rule states that Section 205 of the FPA grants the Commission responsibility to "ensur[e] that all rates and charges for or 'in connection with'" Commission-jurisdictional services "are just and reasonable,"[14] and asserts that the Commission has jurisdiction over DR compensation in ISO/RTO-administered markets "because it directly affects wholesale rates."[15] The Commission also invokes the

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[11] *Demand Response Compensation in Organized Wholesale Energy Markets*, Notice of Proposed Rulemaking, FERC Stats. & Regs. ¶ 32,656 (2010) (the "NOPR").

[12] Final Rule, FERC Stats. & Regs. ¶ 31,322 at P 2.

[13] *Id.* at P 2.

[14] *Id.* at P 112 (*citing* 16 U.S.C. § 824d (2006)).

[15] Final Rule, FERC Stats. & Regs. ¶ 31,322 at P 112 *(citing Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶ 31,281 (2008), *order on*

statement of congressional policy in Section 1252(f) of EPAct 2005 as supporting its claimed jurisdiction to set rates for DR compensation.[16]

III.

REQUEST FOR REHEARING

In enacting the FPA, Congress sought "to draw a bright line easily ascertained, between state and federal jurisdiction," with the Commission enjoying broad and "plenary" jurisdiction over rates for wholesale sales in interstate commerce but no such jurisdiction over rates for retail sales.[17] Despite acknowledging that its "ability to address barriers [to DR participation] is limited to the confines of [its] statutory authority,"[18] the Commission has crossed that bright line in the Final Rule. The Commission lacks authority under the FPA to set rates for DR compensation, and contrary to what the Final Rule suggests, Section 1252(f) of EPAct did not expand the Commission's ratemaking jurisdiction in the slightest, and certainly not to the extent that could justify the Commission's assertion of jurisdiction over DR compensation. The Commission's Final Rule also relies on an unreasonable interpretation of the statutory requirements, and it utterly fails to respond to serious objec-

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reh'g, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292 at P 47, *order on reh'g*, Order No. 719-B, 129 FERC ¶ 61,252 (2009)).

[16] Final Rule, FERC Stats. & Regs. ¶ 31,322 at P 113.

[17] *FPC v. Southern Cal. Edison Co.*, 376 U.S. 205, 215-16 (1964).

[18] Final Rule, FERC Stats. & Regs. ¶ 31,322 at P 115.

tions that were raised and thoroughly articulated in comments submitted on the NOPR.

A. The Commission Lacks Authority To Set Rates, Either Directly or Indirectly, For DR Compensation.

As a "creature of statute," the Commission has only such authority as has been conferred upon it by Congress, and "if there is no statute conferring authority, FERC has none."[19] It is therefore significant that Congress limited the Commission's ratemaking authority under the FPA only to rates charged by "public utilities" for services subject to the Commission's jurisdiction—that is, for wholesale sales or transmission of electric energy in interstate commerce.[20] Section 201(b)(1) of the FPA makes clear that, subject only to certain exceptions not relevant here, the provisions of Part II of the FPA "shall apply to the transmission of electric energy in interstate commerce and to the sale of electric energy in interstate commerce, but shall not apply to any other sale of electric energy."[21]

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[19] *Atlantic City Elec. Co. v. FERC*, 295 F.3d 1, 7 (D.C. Cir. 2002) (internal quotations omitted) (*citing Michigan v. EPA*, 268 F.3d 1075, 1081 (D.C. Cir. 2001); *Louisiana Pub. Serv. Comm'n v. FCC*, 476 U.S. 355, 374 (1986)).

[20] *See* 16 U.S.C. §§ 824, 824d, 824e (2006).

[21] 16 U.S.C. §§ 824(b)(1) (2006). *See Panhandle E. Pipe Line Co. v. FPC*, 332 U.S. 507, 516-17 (1947) (discussing analogous provision of the Natural Gas Act); *Niagara Mohawk Power Corp. v.*

The Commission lacks authority to set "just and reasonable" rates for DR, because, as the Commission held in *EnergyConnect* and recognized in the Final Rule, the provision of DR service does not involve a sale for resale of electric energy, and DR is not a jurisdictional service.[22] Moreover, because there is no meaningful nexus between DR compensation and jurisdictional rates, the Commission's "affecting or pertaining to" jurisdiction may not be used to regulate DR and, in any event, the Commission has made no findings that could support the exercise of its "affecting or pertaining to" jurisdiction. The Commission's expansive interpretation of its jurisdiction in the Final Rule would eviscerate the statutory limits on its authority. Hence, the Commission's interpretation of its statutory authority under the FPA is unreasonable.[23]

1. The Commission Lacks Authority To Directly Set Rates For DR, Because DR Does Not Involve Jurisdictional Wholesale Sales.

Section 35.28(b)(5) of the Commission's regulations appropriately recognizes that DR is "a reduction in the

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FERC, 452 F.3d 822, 824 (D.C. Cir. 2006) (explaining that under Section 201(b) of the FPA, the Commission "has jurisdiction over both the interstate transmission of electricity and the sale of electricity at wholesale in interstate commerce," while "States retain jurisdiction over retail sales of electricity and over local distribution facilities").

[22] Final Rule, FERC Stats. & Regs. ¶ 31,322 at P 64.

[23] *See Chevron U.S.A. Inc. v NRDC, Inc.*, 467 U.S. 837, 845 (1984).

consumption of electric energy by customers from their expected consumption in response to an increase in the price of electric energy or to incentive payments designed to induce lower consumption of electric energy."[24] Because DR is a ***retail "non-purchase"***—a retail purchase that will not be, or was not, made—it is the polar opposite of a Commission-jurisdictional ***wholesale sale***.[25] The Commission emphatically reaffirmed this definition of DR in the Final Rule.[26]

Because the Commission's ratemaking and refund jurisdiction under Sections 205 and 206 are expressly limited to rates charged by public utilities for jurisdictional services,[27] the Commission may not regulate, either directly or indirectly, the rates for retail purchases, including retail purchases made by ***non***-public utility providers of DR services.[28] The same result

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[24] 18 C.F.R. § 35.28(b)(5) (2010).

[25] In *EnergyConnect*, the Commission held that:

> [W]here an entity is only engaged in the provision of demand response services, and makes no sales of electric energy for resale, that entity would not own or operate facilities that are subject to the Commission's jurisdiction and would not be a public utility that is required to have a rate on file with the Commission.

EnergyConnect, 130 FERC ¶ 61,031 at P 30.

[26] *See* Final Rule, FERC Stats. & Regs. ¶ 31,322 at P 64 ("[A]s the Commission previously stated in *EnergyConnect*, the Commission does not view demand response as a resale of energy back into the energy market.").

[27] *See BPA*, 422 F.3d at 918.

[28] *See, e.g., New York v. FERC*, 535 U.S. 1, 20 (2002) (explaining that the Commission's "jurisdiction over the sale of power has been

holds for non-jurisdictional DR services provided by an entity that is a public utility for other purposes (as was the case in *EnergyConnect*). It is well settled law that, where a regulated entity provides both Commission-jurisdictional and non-jurisdictional services, the Commission may exercise its ratemaking authority only with respect to the jurisdictional services.[29]

Because DR is not a jurisdictional service, the Commission has no delegated authority to regulate it. Accordingly, regardless of whether compensation to DR providers is (or is not) too "high"[30] or too "low,"[31] DR compensation, as such, is outside of the Commission's jurisdiction. There are certainly a variety of ways in which the Commission could work to remove barriers to increased DR participation. But what it cannot do is intrude upon State jurisdiction over the rates, terms and conditions of retail electric service, no

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specifically confined to the wholesale market"); *FPC v. Conway Corp.*, 426 U.S. 271, 276-77 (1976) *("Conway")* (stating that the Commission "has no power to prescribe the rates for retail sales" and that the FPA was structured to "foreclose the possibility that the Commission would regulat[e] the nonjurisdictional, retail price").

[29] *See Conway*, 426 U.S. at 279 (1976).

[30] *See, e.g., Colorado Interstate Gas Co. v. FPC*, 324 U.S. 581 (1945).

[31] *See, e.g., United Gas Pipe Line Co.*, Opinion No. 671, 50 F.P.C. 1348, 1387 (1973).

matter how frustrated the Commission may be with the pace of regulatory change at the State level.[32]

2. The Commission Cannot Set Rates For DR Compensation As A Rule Or Regulation "Affecting Or Pertaining To" Jurisdictional Rates.

The Commission has made no showing, or supported its order with any evidence, demonstrating that DR participation is causing jurisdictional rates to become unjust and unreasonable.[33] Even if the Commission had made this showing (and it has not), any remedy may "operate only against the rate of jurisdictional sales."[34] Although the Commission's "affecting" jurisdiction may be broad, it is not broad enough to overcome the express limits on its authority to regulate non-jurisdictional rates. In other words, Sections 205 and 206 of the FPA[35] do not empower the Commission to regulate rates beyond the reach of its jurisdiction under Section 201(b) of the FPA.[36] Consequently, the Commission may not directly regulate the non-jurisdictional rates that DR service providers

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[32] *See Demand Response Compensation in Organized Wholesale Energy* Markets, Transcript at 234:3-11 (Chairman Wellinghoff), Docket No. RM10-17-000 (Sept. 13, 2010).

[33] *See ICC*, 576 F.3d at 477 (explaining that a reviewing court cannot "uphold a regulatory decision that is not supported by substantial evidence on the record as a whole.").

[34] *Conway*, 426 U.S. at 279.

[35] 16 U.S.C. §§ 824d, 824e (2006).

[36] 16 U.S.C. § 824(b) (2006).

receive as a rule or regulation "affecting or pertaining to" Commission-jurisdictional rates.[37]

The Commission is similarly foreclosed from indirectly regulating non-jurisdictional rates through the exercise of its authority over public utilities' jurisdictional rates.[38] The Final Rule, which requires public utilities (*i.e.*, each ISO and RTO) to pay qualifying DR resources full LMP, would do precisely that. Because DR is not a service subject to the Commission's ratemaking jurisdiction, however, the Commission's proposal represents an impermissible "attempt[] to do indirectly what it [may] not do directly."[39]

To be sure, the holding in *Connecticut Department of Public Utility Control v. FERC*[40] underscores the fact that the Commission does, in fact, possess broad jurisdiction to regulate practices affecting rates for wholesale sales. But this decision cannot be read to support the assertion of jurisdiction over DR compen-

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[37] Final Rule, FERC Stats. & Regs. ¶ 31,322 at P 112 (citing 16 U.S.C. § 824d (2006)).

[38] *See, e.g., Richmond*, 574 F.2d at 620 (rejecting petitioner's argument that the Federal Power Commission (the "FPC") could indirectly impose a requirement on a public utility (involuntary wheeling) that the FPC could not impose directly, by conditioning its approval of the public utility's jurisdictional rates on the wheeling requirement, because "[w]hat the Commission is prohibited from doing directly it may not achieve by indirection.").

[39] *Altamont Gas Transmission Co. v. FERC*, 92 F.3d 1239, 1248 (D.C. Cir. 1996).

[40] 569 F.3d 477 (D.C. Cir. 2009) ("*Connecticut DPUC*").

sation. In *Connecticut DPUC*, the Court of Appeals for the District of Columbia Circuit (the "D.C. Circuit") held that, because the Commission had jurisdiction ***directly*** to regulate the capacity prices in question (that is, to set rates charges by public utilities for wholesale sales of electric capacity), it could also ***indirectly*** regulate capacity prices through setting the inputs that would affect the prices paid for capacity.[41] In other words, the power to set rates directly "include[s] the power to do so indirectly."[42] Unlike the capacity prices at issue in *Connecticut DPUC*, however, the Commission lacks the authority to set rates for retail sales directly. Because this antecedent condition is not satisfied, *Connecticut DPUC* provides no support for the Commission's assertion of jurisdiction over rates for DR services.

The Commission is not allowed to circumvent the express limitations on its ratemaking authority. The Commission's "affecting" jurisdiction under the statutory provisions extends only to "classifications, practices, and regulations," as well as contracts, affecting "such rates," *i.e.*, rates charged by public utilities for

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[41] In *Connecticut DPUC*, the Court of Appeals for the D.C. Circuit upheld a Commission order accepting the Installed Capacity Requirement (the "ICR"), which the court described as "a key input into the market-based mechanism" for determining prices in the capacity market administered by ISO New England Inc. *Id.* at 478-79.

[42] *Id.* at 482.

FERC-jurisdictional sales.[43] Notably absent from this list are "rates" for (or terms and conditions of) non-jurisdictional service that affect public utilities' jurisdictional rates. The logic of the Commission's claim to possess "affecting" jurisdiction over DR compensation[44] would lead inexorably to the exercise of jurisdiction over State-regulated retail rates, because retail rates regularly have an indirect effect on wholesale rates, *e.g.*, by increasing or decreasing consumption in a manner that would, in turn, affect prices in wholesale markets. Such a result is at war with both the letter and intent of the FPA.

DR is no different than any other non-jurisdictional factor that may "affect" the price of jurisdictional rates (*e.g.*, steel, cement, coal, etc.). Even if an increase in DR compensation in energy markets might lower jurisdictional rates, that effect would not, in and of itself, empower the Commission to set rates for DR, any more than the Commission would be justified in reaching out to regulate retail electric rates or the prices of cement, steel, coal, or other goods or services that affect the price of electricity. To argue that it does would read out of the FPA the express restrictions on the Commission's ratemaking authority and would thus violate one of the cardinal rules of statutory construction—namely, that a statute must be read to "avoid an interpretation that renders

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[43] 16 U.S.C. §§ 824d(a), 824d(c), and 824e(a) (2006).

[44] *See* Final Rule, FERC Stats. & Regs. ¶ 31,322 at P 112.

any part of it superfluous and does not give effect to all of the words used by Congress."[45]

Nor can the Commission assert jurisdiction over DR compensation as a "component" of jurisdictional, market-based rates for energy in organized markets. DR represents retail purchases of electric energy that have ***not*** been made. By no stretch of the imagination can the rate for a non-jurisdictional, retail non-purchase be described as a "component" of a rate for wholesale sales. And, in any event, nothing in the Commission's order makes that connection in a manner that would be considered reasoned decision-making by a Court.

The level of DR compensation is vitally different from the non-jurisdictional rates at issue in *Transmission Agency of Northern California v. FERC*.[46] In that case, the D.C. Circuit held that the Commission was permitted to review whether a non-jurisdictional "rate," which was to be used as a component to calculate a jurisdictional rate, was just and reasonable ***solely*** for the purpose of ensuring that the jurisdictional rate in question was just and reasonable,[47] but ***not*** to

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[45] *Beisler v. Comm'r*, 814 F.2d 1304, 1307 (9th Cir. 1987).

[46] *Transmission Agency of N. Cal. v. FERC*, 495 F.3d 663 (D.C. Cir. 2007) ("*TANC*").

[47] In *TANC*, the Court affirmed the Commission's decision to review the justness and reasonableness of the transmission revenue requirement ("TRR") of the City of Vernon, California ("Vernon"), a governmental entity excluded from the definition of public utility, because Vernon's TRR would be added to the TRR of other

determine whether the non-jurisdictional seller was receiving adequate or excessive compensation. In fact, notwithstanding the Commission's finding that the non-jurisdictional rate that was a component of the jurisdictional rate was excessive, the court rejected the Commission's attempt to order refunds.[48]

3. The Commission's Interpretation Of Its Statutory Authority Is Unreasonable.

Even assuming *arguendo* that the Commission's assertion of jurisdiction over DR compensation were not foreclosed by the FPA's plain terms, it is still an unreasonable interpretation of the Commission's stat-

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transmission owners and used to determine the rates for jurisdictional transmission service on the California Independent System Operator Corporation ("CAISO") grid. The court found that the Commission had "sufficiently demonstrated that it is impossible to ensure that CAISO's rates are just and reasonable without reviewing Vernon's TRR under the same standard." *Id.* At 672.

[48] *Id.* at 674; *see also BPA*, 422 F.3d at 921 (noting that the Commission's "long-standing interpretation of §§ 205 and 206 confirm that governmental entities/non-public utilities lie outside its ratemaking and refund authority"). While the *BPA* and *TANC* courts discussed the exclusion of governmental entities from the definition of public utility in FPA Section 201(f), 16 U.S.C. § 824(f) (2006), this statutory exemption was not the sole or even principal basis for their holdings. Instead, the crucial issue for both the *BPA* and *TANC* was that the Commission's ratemaking and refund jurisdiction under Sections 205 and 206 is expressly limited to ***public utilities***, and these holdings apply equally to any entity that is not a public utility, irrespective of whether that entity also enjoys the exemption for governmental entities.

utory authority under the FPA. That is to say, even if there were some ambiguity in Sections 205 and 206 regarding the scope of the Commission's authority to regulate practices that "affect" jurisdictional rates, such ambiguity, without more, may not be interpreted as a congressional delegation of authority to resolve that ambiguity.[49]

Courts are particularly reluctant to infer a delegation of authority where, as here, a federal agency seeks to regulate an area that has been traditionally regulated by the States.[50] As the Supreme Court has explained, Congress is presumed not to extend federal regulation to areas that have traditionally fallen under the States' control through "muffled hints" or "obscure grant[s] of authority."[51] When Congress's intent to displace historical State practice "is doubtful, our federal system demands deference to long-established

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[49] *See, e.g., Michigan v. EPA*, 268 F.3d 1075, 1082 (D.C. Cir. 2001) ("[m]ere ambiguity in a statute is not evidence of a delegation of authority."). By the same token, the Commission may not presume that it is authorized to regulate DR from the fact that the FPA does not expressly preclude the Commission from regulating DR. *See, e.g., Ry. Labor Exec. Ass'n v. Nat'l Mediation Bd.*, 29 F.3d 655, 671 (D.C. Cir. 1994).

[50] *See, e.g., ABA*, 430 F.3d at 471-472 (affirming district court's finding that the Federal Trade Commission had exceeded its statutory authority under a statutory provision governing financial institutions where it sought to regulate the practice of law, which "is traditionally the province of the states.").

[51] *Gonzales v. Oregon*, 546 U.S. 243, 274-75 (2006).

traditions of state regulation."[52] Accordingly, courts will uphold an agency's assertion of jurisdiction to reach into areas of traditional State sovereignty only where Congress has made "its intention to do so 'unmistakably clear in the language of the statute.'"[53]

DR is a retail non-purchase, and retail rates have traditionally been subject to State or local regulation. There is nothing in the FPA suggesting, much less stating in clear and unmistakable terms, that Congress intended to authorize the Commission to regulate DR compensation. The Commission's assertion that Congress has delegated it authority to regulate this non-jurisdictional, retail non-purchase is an impermissible and unreasonable interpretation of its statutory authority under the FPA.

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[52] *BFP v. Resolution Trust Corp.*, 511 U.S. 531, 546 (1994).

[53] *Will v. Michigan Dep't of State Police*, 491 U.S. 58, 65 (1989) (*quoting Atascadero State Hospital v. Scanlon*, 473 U.S. 234, 242 (1985)). The Supreme Court has explained that this "plain statement rule":

> is nothing more than an acknowledgement that the States retain substantial sovereign powers under our constitutional scheme, power with which Congress does not readily interfere.

Gregory v. Ashcroft, 501 U.S. 452, 461 (1991); *see also Medtronic, Inc. v. Lohr*, 518 U.S. 470, 485 (1996).

B. The Energy Policy Act Of 2005 Did Not Empower The Commission To Regulate DR Compensation.

In addition to asserting that it may regulate DR compensation pursuant to Section 205 of the FPA,[54] the Commission implies that Section 1252(f) of EPAct 2005—which states that "[i]t is the policy of the United States" to encourage DR and to remove barriers to the participation of DR in energy markets[55]—supports its claim of jurisdiction over DR compensation.[56] The Commission's apparent reliance on this provision is misplaced. Section 1252(f) of EPAct 2005 is a statement of policy; it does not expand the Commission's jurisdiction to implement that policy.[57] As the D.C.

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[54] Final Rule, FERC Stats. & Regs. ¶ 31,322 at P 112 (*citing* 16 U.S.C. § 824d (2006)).

[55] EPAct 2005 § 1252(f).

[56] Final Rule, FERC Stats. & Regs. ¶ 31,322 at PP 11, 113.

[57] Subsequent legislation has provided further clarification, if any were needed, that the Commission has not been granted ratemaking jurisdiction with respect to DR. Specifically, the Energy Independence and Security Act of 2007 ("EISA"), Pub. L. No. 110-140, 121 Stat. 1492 (2007), includes provisions addressing the Commission's authority and responsibilities with respect to DR, none of which delegate to the Commission the authority to adopt mandatory rules of any kind. EISA includes provisions directing the Commission to collaborate with other federal agencies to develop standards and protocols for "smart grid" technologies, including DR. *See* EISA §1305(d) (*to be codified at* 15 U.S.C. § 17385(d)). These standards would not be mandatory or enforceable by the Commission. *See Smart Grid Policy*, 128 FERC ¶ 61,060 at P 23 (2009). Moreover, Section 529 of EISA directs the Commission, working with public and private stakeholders, to prepare two

Circuit recently observed in striking down the Federal Communications Commission's "net neutrality" rules: "Policy statements are just that—statements of policy. They are not delegations of authority."[58] The Commission cannot rely on a policy statement alone as the legal basis for promulgating a given regulation; it must show that its actions in furtherance of the policy are supported by "an express delegation of authority."[59]

To the extent the Commission wishes to regulate DR compensation, it would need to rely on an express delegation of authority under the FPA. Reliance on Section 1252(f) of EPAct 2005 is particularly misplaced where the actions contemplated directly contravene the duly enacted express limitations on the Commission's authority, like those in Sections 201, 205 and 206 of the FPA.[60] Moreover, the Commission's apparent

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reports (a "National Assessment of Demand Response" and a "National Action Plan on Demand Response" (or "National DR Action Plan")) to develop recommendations to Congress regarding measures that would facilitate the adoption and implementation of DR by the States and market participants.

[58] *Comcast*, 600 F.3d at 654 (striking down an FCC order regulating the internet network management practices of a cable television provider that the FCC claimed was authorized under a similar provision of the Federal Communications Act, which stated that "[i]t is the policy of the United States . . to promote the continued development of the Internet and other interactive computer services," 47 U.S.C. § 230(b) (2006)).

[59] *Comcast*, 600 F.3d at 652.

[60] *See, e.g., Richmond*, 574 F.2d at 620 (noting that the FPC had the "authority to impose conditions or requirements 'necessary or

urgency to take actions to promote DR that are not mandated, or even authorized, by this provision is hard to square with the leisurely pace with which the prime DR-related initiative actually required by Congress (namely, adoption of the National DR Action Plan pursuant to EISA Section 529[61]) is being pursued by the federal government.[62]

C. The Commission's Decision Is Arbitrary and Capricious Because It Fails To Address Serious Objections To The Commission's Proposed Approach.

The Final Rule ignores, or cursorily dismisses, the jurisdictional arguments set forth above,[63] which were presented, in detail, in comments on the NOPR.[64] Instead, the Commission simply repeats its assertion that it may regulate DR compensation pursuant to Section 205 of the FPA "because it directly affects

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appropriate to promote the policies'" of the FPA, but that "such conditions may not contravene" the express requirements of the FPA) (internal citations omitted).

[61] EISA § 529 (*to be codified at* 42 U.S.C. § 8279).

[62] Joint Petitioners recognize that the delay in implementing the National DR Action Plan appears to be attributable to inaction on the part of the Office of Management and Budget, and certainly not to any inaction on the part of the Commission.

[63] *See* Final Rule, FERC Stats. & Regs. ¶ 31,322 at PP 112-113.

[64] *See, e.g.*, Comments of the Electric Power Supply Association at 31-37, Docket No. RM10-17-000 (filed May 12, 2010); Reply Comments of the Electric Power Supply Association at 49-53, Docket No. RM10-17-000 (filed June 30, 2010).

wholesale rates"[65] and because the Commission's actions are consistent with the policy statement in EPAct Section 1252(f).[66] By failing to respond meaningfully to the serious objections to its jurisdiction, the Commission failed to satisfy its "fundamental obligation to engage in reasoned decision making,"[67] which necessarily "renders its decision arbitrary and capricious."[68]

IV.

CONCLUSION

WHEREFORE, for the foregoing reasons, Joint Petitioners respectfully request that the Commission grant rehearing of the Final Rule.

Respectfully submitted,

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[65] Final Rule, FERC Stats. & Regs. ¶ 31,322 at P 112 (citations omitted).

[66] *See id.* at PP 11, 113.

[67] *Moraine Pipeline*, 906 F.2d at 8.

[68] *CAPP*, 254 F.3d at 299; *see also State Farm*, 463 U.S. at 29.

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Dated: Apr. 14, 2011

UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. RM10-17-000

DEMAND RESPONSE COMPENSATION IN ORGANIZED WHOLESALE MARKETS

Apr. 14, 2011

Request for Rehearing of the Organization of MISO States

Pursuant to Rule 713 of the Federal Energy Regulatory Commission's ("Commission") Rules of Practice and Procedure, 18 C.F.R. §385.713, the Organization of MISO States ("OMS") submits this Request for Rehearing regarding the Commission's Final Rule issued in this proceeding on March 15, 2011 ("Order 745").[1] OMS respectfully requests that the Commission grant rehearing of Order 745.

I. Background

On March 18, 2010, the Commission issued a Notice of Proposed Rulemaking in Docket No. RM10-17 proposing a rule that would require RTOs operating organized electric markets to pay demand response resources the full LMP for retail load reductions. On

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[1] 134 FERC ¶ 61,187.

May 13, 2010, OMS submitted comments to the Commission averring: (A) that the correct compensation for retail load reductions in wholesale markets is LMP - Retail Rate, (B) that payment of the full LMP as proposed by the Commission in the NOPR would result in a "distortionary subsidy" to Aggregators of Retail Customers ("ARCs") and participating retail customers, (C) that compensation paid to demand response resources must be considered in conjunction with the recovery of the cost of these payments by RTOs, and (D) that adoption of the Proposed Rule would encourage state commissions to opt out of RTO demand response programs, as allowed by the Commission in Order 719-A.

On August 2, 2010, the Commission issued a Supplemental Notice of Proposed Rulemaking and Notice of Technical Conference seeking comments on (a) whether the Commission should adopt a "net benefits test" for determining the conditions under which demand response providers should be compensated, (b) if so, how should such a test be structured, and (c) how should the costs of demand response be allocated to market participants. The Commission conducted a technical conference on these issues on September 13, 2010.

On March 15, 2011, the Commission issued Order 745 establishing standards for the compensation of demand response resources in organized wholesale markets. The Commission decided that those demand response resources should be compensated at the full

LMP during periods when a "net benefits test" is satisfied, determined that the costs of demand response should be allocated to all entities that purchase energy in the "relevant energy market," and established several compliance requirements for RTOs which operate organized wholesale markets.

II. Statement of Issues and Specification of Errors

OMS submits the following specification of errors:

A. The Commission erred when it determined that the compensation for load reductions should be the full LMP and that payments should only be made when such load reductions pass a net benefits test.

B. The Commission erred when it determined that the costs associated with demand response compensation should be allocated to all entities from the relevant market area(s) where the demand response reduces the market price for energy.

III. Request for Rehearing

A. The Commission erred when it determined that the compensation for load reductions should be the full LMP and that payments should only be made when such load reductions pass a net benefits test.

OMS has also been involved in several efforts during the past several years by the Midwest ISO and the other Midwest ISO stakeholders to improve the efficiency of the energy and ancillary services market by

improving price signals. These efforts have included the incorporation of various types of demand response measures and price sensitive loads into the market, the refinement of the LMP algorithm to include certain costs in the LMP that are currently recovered through uplifts (sometimes referred to as "extended LMP"), and the development of procedures and compensation mechanisms to accommodate the participation of ARCs in the market.

The Midwest ISO, OMS and the other Midwest ISO stakeholders have devoted significant resources to the development of the Midwest ISO's proposal to incorporate ARCs into the Midwest ISO market. The OMS State Commissions have a particular interest in this issue given our regulatory oversight of retail electric service. OMS developed significant understanding of the issues associated with ARC participation in the Midwest ISO market because the State Commissions' institutional, ratemaking, legal and economic expertise bridges the wholesale market and the provision of retail service.

The Midwest ISO proposal filed on October 2, 2009, in Docket No. ER09-1049-002 was supported by OMS and many other stakeholders, including LSEs. The proposal had two main components. First, compensation for load reductions would be equal to the LMP —Retail Rate. Secondly, the cost of the payments made to ARCs and participating retail customers would be directly assigned to the LSE which provides retail service to the customer. This general frame-

work was also supported by many commenters in this rulemaking proceeding.

The Commission has now determined that it is appropriate to pay ARCs the full LMP for load reductions and to utilize a net benefits test in order to determine the conditions under which such payments should be made. This determination is not just and reasonable because it will result in excessive compensation for certain demand response resources. In addition, the net benefits test relies on a static price threshold which will result in inefficient deployment of demand response resources. That is, the net benefits test will preclude the deployment of demand response resources at certain times when it would otherwise be efficient to do so. In short, the Commission has proposed to cure one inefficient price signal, a difference between wholesale prices and retail prices, with another inefficient price signal, payment of the full LMP for load reductions combined with a static and inefficient net benefits test.

As stated above, the State Commission members of OMS have considerable expertise in the legal and practical issues associated with retail ratemaking, such as metering and billing. OMS believes that the Midwest ISO relied on this expertise when it developed its proposal for incorporating ARCs in the Midwest ISO markets. During the stakeholder process that was used to develop this proposal, OMS and many other stakeholders were concerned that the payment of the full LMP for load reductions without subtracting the

retail rate could leave LSE's and nonparticipating customers bearing the costs of load reductions. State Commission members of OMS were concerned that such an outcome could only be prevented through complex and costly changes to billing and metering systems that would result in charging the retail rate to participating customers for load reductions. The Midwest ISO proposal discussed above eliminated this concern by subtracting the retail rate from the LMP as part of the compensation formula.

The OMS mentioned its concern about the expense and complexity of correcting the payment of a full LMP in its comments in this proceeding. It is often gratifying when an intervenor discovers that the Commission has relied upon an argument advanced by that intervenor as support for the Commission's determination. However, it was surprising for OMS to discover that the argument OMS had advanced in its comments was used instead to support a Commission determination opposite to the policy advice that had been proffered by OMS.

In Order 745 at P.107, the Commission quoted the OMS comments to support the Commission's determination that retail regulatory authorities could make adjustments to retail rates in order to correct infirmities that would result from the payment of the full LMP:

For example, the OMS asserts,

> If the Commission were to adopt the proposed rule, state commissions and LSEs could correct this distorted price signal by revising retail tariffs for customers that do business with ARCs in order to charge the retail rate to participating customers for energy which was not consumed or metered as a result of load reductions.

However, the position supported by the OMS comments was exactly the opposite. This is easily seen by a reading of the full paragraph from the OMS submittal.

> If the Commission were to adopt the proposed rule, state commissions and LSEs could correct this distorted price signal by revising retail tariffs for customers that do business with ARCs in order to charge the retail rate to participating customers for energy which was not consumed or metered as a result of load reductions. **However, these tariff revisions could be complex, time consuming and could possibly involve legal issues—namely, billing retail customers for energy which they have not consumed and which was not metered. LSEs would be forced to develop and implement billing mechanisms for participating retail customers in order to accommodate billing information from outside of their normal metering and data acquisition systems from the RTO's Measurement and Verification system. Ironically, state commissions would be faced with the task of revising retail rate structures in order to correct a price distortion created by a wholesale market**

pricing mechanism which was intended to improve price signals. (Emphasis Added)

The most significant advantage of the proposed Midwest ISO compensation formula (LMP—Retail Rate) is that it automatically sends a price signal to ARCs and retail customers that the RTO will provide compensation for load reductions whenever the LMP exceeds the retail rate. The net benefit test approved by the Commission will be static over the course of at least one month will be based on stagnant load and cost data. It will preclude the payment of compensation during periods when load reductions may otherwise be cost effective for individual customers. For this reason, the imposition of the net benefits test is not reasonable.

OMS urges the Commission to grant rehearing on this issue and to determine that the correct compensation for load reductions is the LMP—Retail Rate and to eliminate the requirement that RTOs use a net benefit test to determine when demand response is cost effective.

B. The Commission erred when it determined that the costs associated with demand response compensation should be allocated to all entities from the relevant market area(s) where the demand response reduces the market price for energy.

Opportunities for demand response in wholesale markets arise when differences exist between whole-

sale market prices and retail rates. These differences result in inefficient consumption decisions by retail customers. One solution to this inefficiency is to narrow or eliminate these price differentials through improvements to retail rate structures. Such rate structures provide for more variability in retail rates, especially during periods when wholesale market prices are relatively high and the differential between standard retail rates and wholesale market prices is relatively greater. Many State Commissions and LSEs, including members of OMS and LSEs in the Midwest ISO region, have or are considering significant investments in Smart Metering technologies and infrastructure with the goal of improving retail rate structures which would eliminate or narrow such differences.

OMS has taken the position that the costs of payments that are made to ARCs for wholesale demand response should be recovered from the LSE that provides retail service to the customer that provides such load reductions. These load reduction opportunities only arise due to differences between individual LSEs' retail rates and wholesale market prices. Therefore, from an equity standpoint, OMS believes that these same LSE's should be assessed the costs of demand response. In addition, OMS believes that direct assignment of these costs would create an incentive for LSE's to more closely align their retail rates with wholesale market costs.

In Order 745 the Commission has determined that "the costs associated with demand response compensation should be [recovered] proportionally [from] all entities that purchase form the relevant energy market in the area(s)" in which the market price for energy is reduced as a result of the demand response.[2] However, it is not clear from the rule how these "relevant market area(s)" will be determined. By their very nature RTO energy markets are dynamic and the algorithms used to compute LMPs are complex. It may be impossible to conduct an after-the-fact analysis to determine the effect of a load reduction on hundreds or thousands of pricing nodes in order to make a determination as to where and when nodal LMPs were affected by a load reduction.

The Commission's determination to allocate the costs of load reductions across an indefinite region is not just and reasonable because the approved cost allocation provides no incentive for LSE's to improve their rate structures and it is not clear how the regions to which the costs will be allocated will be determined.

OMS urges the Commission to grant rehearing on this issue.

IV. Conclusion

OMS and other stakeholders worked cooperatively with the Midwest ISO through the stakeholder process to develop the proposal to incorporate ARCs in the

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[2] Order 745, P. 100.

Midwest ISO markets which was proposed by the Midwest ISO in Docket No. ER09-1049-002. In its Comments filed in that proceeding on November 5, 2009, OMS supported the Midwest ISO's proposed compensation formula [LMP—Retail Rate] and its proposal to collect the cost of load reductions from the LSEs where those load reductions occurred. In that proceeding and in the current rulemaking, OMS cautioned the Commission that the participation of ARCs in wholesale markets should not establish inefficient price signals which distort behavior and result in a cost burden on other customers. The Commission has done exactly that in Order 745.

In its comments in this rulemaking, OMS cautioned the Commission that the adoption of the Proposed Rule would encourage state commissions to opt out of RTO demand response programs. The Commission has stated numerous times its objective to eliminate barriers to demand response. OMS is concerned that the cumbersome and inefficient arrangement approved by the Commission in Order 745 will not advance that objective.

In general, all of the State Commission members of OMS have taken a "wait and see" attitude toward ARCs. As the Commission is aware, several of the State Commission members have taken actions to restrict the participation of ARCs in their states pending a Commission decision on the Midwest ISO proposal and this rulemaking. Instead of alleviating concerns,

Order 745 has created additional concerns on the part of state commissions.

For the reasons discussed above, OMS respectfully requests that the Commission grant rehearing of Order 745.[3]

Respectfully submitted,

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Dated: Apr. 14, 2011

[3] The Kentucky Public Service Commission abstained from voting on this pleading.

UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. RM10-17-000

DEMAND RESPONSE COMPENSATION IN ORGANIZED
WHOLESALE ENERGY MARKETS

Apr. 14, 2011

REQUEST FOR REHEARING AND CLARIFICATION OF OLD DOMINION ELECTRIC COOPERATIVE, THE AMERICAN PUBLIC POWER ASSOCIATION, AND THE NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION

I. INTRODUCTION

Pursuant to Section 313 of the Federal Power Act ("FPA"), 16 U.S.C. § 8251 (2009), and Rule 713 of the Rules and Regulations of the Federal Energy Regulatory Commission ("Commission" or "FERC"), 18 C.F.R. § 385.713 (2010), Old Dominion Electric Cooperative ("ODEC"), the American Public Power Association ("APPA"), and the National Rural Electric Cooperative Association ("NRECA")(collectively, "Joint Parties") hereby file this request for rehearing and

clarification of Order No. 745,[1] the Final Rule issued in the above-referenced proceeding on March 15, 2011. As demonstrated herein, the Commission erred in mandating that each and every independent system operator ("ISO") and/or regional transmission organization ("RTO") adopt rules to compensate demand response resources at the full locational marginal price ("LMP"), during those periods where such resources are able to displace generation resources, and dispatch of demand response resources is determined to be cost-effective based upon a FERC-mandated "net benefits test." Therefore, Joint Parties request that the Commission grant rehearing of the full-LMP compensation mandate of Order No. 745 and direct each individual RTO and ISO to either work with its stakeholders and propose the appropriate compensation for demand response resources and test for when such resources should be dispatched instead of generation resources, if necessary; or adopt the "LMP minus G" compensation mechanism and forego the net benefit test. Joint Parties also request that the Commission clarify that it will address application of the cost allocation requirements on a case-by-case basis during the compliance process.

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[1] *Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, 134 FERC ¶ 61,187 (2011) ("Order No. 745").

II. IDENTIFICATION OF ERRORS

In satisfaction of Rule 713(c)(1) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 713(c)(1)(2010), Joint Parties identify the following errors in Order No. 745, discussed more fully in Section IV below:

1. Order No. 745 erred by mandating full-LMP compensation for the service provided by all demand response resources that pass the capability and net benefits tests.

2. Order No. 745 erred in departing from the Commission's policy of accommodating regional variations in RTO and ISO market design.

3. Order No. 745 erred by departing from the Commission's policy of allowing regional entities to work with their stakeholders to develop their market design.

4. Order No. 745 erred in failing to consider record evidence regarding the different types of demand response products, and/or differences among the RTO/ISO regions and whether such differences dictate a regional approach to demand response compensation.

5. Order No. 745 erred in mandating a standardized, full-LMP compensation mechanism without explaining how the mechanism will achieve the identified goal of eliminating barriers to

demand response participation in organized wholesale energy markets.

6. Order No. 745 erred in failing to address evidence that the full-LMP compensation for demand response resources will actually hamper development of demand response resources.

7. Order No. 745 erred in determining that demand response resources are comparable to generation resources.

8. Order No. 745 erred in determining that the full-LMP compensation mandate will result in just and reasonable rates.

9. Order No. 745 erred in rejecting the "LMP minus G" demand response compensation mechanism which takes into account the avoided generation cost for demand response resources.

10. Order No. 745 erred in adopting the net benefits test.

11. Order No. 745 erred in adopting the cost-allocation mandate without explaining why any currently-effective demand response cost allocation methodologies are unjust and unreasonable.

12. The Commission erred in failing to clarify the cost allocation mechanism.

III. STATEMENT OF ISSUES

Pursuant to Rule 713(c)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.713(c)(2)(2010), Joint Parties present the following statement of issues:

1. Whether the Commission's determinations that any compensation for demand response resources other than the full LMP mechanism adopted in Order No. 745 is unjust and unreasonable, and that full-LMP compensation mandate will result in just and reasonable rates, are arbitrary and capricious. 16 U.S.C. § 824e; *Louisiana Pub. Serv. Commission v. System Energy Resources, Inc., et al.*, 124 FERC ¶ 61,003 (2008); *Motor Vehicle Mfrs. Ass'n of U.S. v. State Farm Mut. Auto Ins. Co.*, 463 U.S. 29, 43 (1983); *Hatch v. FERC*, 654 F.2d 825, 834 (D.C. Cir. 1981); 5 U.S.C. § 706(2)(A)(2006).

2. Whether Order No. 745 is arbitrary and capricious because it departs without justification from the Commission's policy of allowing regional variations as well as its policy of allowing RTOs and ISOs, working together with their stakeholders, to design their market mechanisms. *Motor Vehicle Mfrs. Ass'n of U.S. v. State Farm Mut. Auto Ins. Co.*, 463 U.S. 29, 43 (1983); *Hatch v. FERC*, 654 F.2d 825, 834 (D.C. Cir. 1981); 5 U.S.C. § 706(2)(A)(2006).

3. Whether the Commission failed to engage in reasoned decision-making in mandating a standardized full-LMP compensation method for demand response resources in RTOs and ISOs. *Northern States Power Co. v FERC*, 30 F.3d. 177, 180 (D.C. Cir. 1994) (citing *Town of Norwood v. FERC*, 962 F.2d. 20, 222 (D.C. Cir. 1992)).

4. Whether the Commission failed to engage in reasoned decision-making by failing to address record evidence regarding the different types of demand response products, and/or differences among the RTO/ISO regions and whether such differences dictate a regional approach to demand response compensation. *Northern States Power Co. v FERC*, 30 F.3d. 177, 180 (D.C. Cir. 1994) (citing *Town of Norwood v. FERC*, 962 F.2d. 20, 222 (D.C. Cir. 1992)); *NorAm GasTransmission Co. v. FERC*, 148 F.3d. 1158, 1165 (D.C. Cir. 1998); *KN Energy Inc. v. FERC*, 968 F.2d 1295, 1303 (D.C. Cir. 1992); 5 U.S.C. § 706(2)(A) (2006).

5. Whether the Commission failed to engage in reasoned decision-making by mandating a standardized, full-LMP compensation mechanism for demand response resources without explaining how the mechanism will achieve the identified goal of eliminating barriers to demand response participation in organized wholesale energy markets.

6. Whether Order No. 745 is arbitrary and capricious because the Commission failed to address evidence that the full-LMP compensation mandate will actually hamper development of demand response resources, failed to adequately address record evidence that demand response resources are not comparable to generation resources, and failed to address concerns over the adverse impact that the compensation mechanism will have on load-serving entities. *Northern States Power Co. v. FERC*, 30 F.3d. 177, 180 (D.C. Cir. 1994)(citing *Town of Norwood v. FERC*, 962 F.2d. 20, 222 (D.C. Cir. 1992)).

7. Whether the Commission's rejection of the "LMP minus G" demand response compensation mechanism which takes into account the avoided generation cost for demand response resources renders Order No. 745 arbitrary and capricious. *Northern States Power Co. v FERC*, 30 F.3d. 177, 180 (D.C. Cir. 1994) (citing *Town of Norwood v. FERC*, 962 F.2d. 20, 222 (D.C. Cir. 1992)); *NorAm Gas Transmission Co. v. FERC*, 148 F.3d. 1158, 1165 (D.C. Cir. 1998); *KN Energy Inc. v. FERC*, 968 F.2d 1295, 1303 (D.C. Cir. 1992).

8. Whether the net benefits test adopted in Order No. 745 can remedy the fact that the full-LMP compensation mechanism will result in rates that are unjust and unreasonable. *Moraine*

Pipeline Co. v. FERC, 906 F.3d 5, 8 (D.C. Cir. 1990); *Canadian Ass'n of Petroleum Producers v. FERC*, 254 F.3d 289, 299 (D.C. Cir. 2001).

9. Whether the cost-allocation directives in Order No. 745 are just and reasonable.

IV. DISCUSSION

A. The Commission's Departure in Order No. 745 from Its Policies of Accommodating Regional Variations and Stakeholder-Involved Market Design is Arbitrary and Capricious, and Does Not Reflect Reasoned Decision-making

As the Commission acknowledged in Order No. 745, each RTO and ISO has until now been able to develop its own methodology for compensating demand response resources.[2] As a result, there are different demand response compensation mechanisms on file with the Commission, which have each been determined just and reasonable by the Commission. Thus, the existing compensation methods on file with the Commission are the filed rate, and cannot be replaced per FPA Section 206 absent a determination, based on record evidence, that the current tariff provisions are unjust and unreasonable, and that the proposed replacement is just and reasonable.[3] In Order No. 745, the Commission presumably is acting pursuant to its

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[2] Order No. 745 at P 14.

[3] 16 U.S.C. § 824e; *Louisiana Pub. Serv. Commission v. System Energy Resources, Inc., et al.*, 124 FERC ¶ 61,003 (2008).

authority under FPA Section 206, although the Commission makes no mention of either this provision of its governing statute or how the Final Rule analysis meets the FPA Section 206 requirement. Instead, Order No. 745 summarily determines that each RTO and ISO demand response compensation mechanism that is not based on full LMP (subject only to the Commission's newly-constructed "net benefits" test) is unjust and unreasonable, and directs the adoption of the full-LMP compensation mechanism mandated in the Final Rule.[4] Order No. 745 is arbitrary and capricious because it departs without justification from the Commission's policy of allowing regional variations as well as its policy of allowing RTOs and ISOs, working together with stakeholders, to design their relevant market mechanisms.[5] Moreover, because the Commission has not provided the reason

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[4] *See id.* at P 47 " when a demand response resource has the capability to balance supply and demand as an alternative to a generation resource, and when dispatching and paying LMP to that demand response resource is shown to be cost-effective as determined by the net benefits test described herein, payment by an RTO or ISO of compensation other than the LMP is unjust and unreasonable. When these conditions are met, we find that payment of LMP to these resources will result in just and reasonable rates for ratepayers." (footnote omitted).

[5] *See, e.g., Hatch v. FERC*, 654 F.2d 825, 834 (D.C. Cir. 1981) ("While it is generally true that 'an agency is free to alter its past rulings and practices even in an adjudicatory setting . it is equally settled that an agency must provide a reasoned explanation

for its decision that any compensation for demand response resources that does not equal full LMP (subject only to a "net benefits" test) is *per se* unjust and unreasonable, nor demonstrate why mandating full LMP is just and reasonable, the Commission has failed to engage in reasoned decision making. These errors must be corrected on rehearing.

The Commission has a policy of accommodating regional differences in RTO/ISO market design, and allowing regional entities to work with their stakeholders to develop their market design. In its Order No. 719[6] process, the Commission specifically rejected certain arguments because they "fail[ed] to appreciate the differences in market design that exist in each region"[7] and noted that it had adopted "different reforms, at different time in each region to reflect the differing characteristics of each market."[8] In Order No. 719, the Commission adopted reforms for RTOs and ISOs in the areas of demand response, long-term power contracting, market monitoring policies, and

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for any failure to adhere to its own precedents.'") (citations omitted).

[6] *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, 125 FERC ¶ 61,071 (2008), *order on reh'g.*, Order No. 719-A, 128 FERC ¶ 61,059 (2009); *order on reh'g and clarification*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

[7] *Wholesale Competition in Regions with Organized Electric Markets*, Notice of Proposed Rulemaking, FERC Stats. and Regs. ¶ 32,628 at P 18 (2008).

[8] *Id.*

RTO and ISO responsiveness. However, rather than mandate a particular outcome, the Commission recognized that "[s]ignificant differences exist between regions, including differences in industry structure, mix of ownership, sources of electric generation, population densities, and weather patterns"[9] and, therefore allowed "each RTO or ISO to consult with its stakeholders and make a compliance filing that explains how its existing practices comply with the Final Rule in this proceeding, or its plans to attain compliance."[10]

Rather than adhere to the Commission's recognition of regional differences and the need to allow regional entities and their stakeholders flexibility in developing their own market designs, Order No. 745 mandates a single compensation mechanism for all demand response resources in every RTO and ISO—full LMP. The removal of all existing RTO and ISO demand response compensation mechanisms on file with the Commission and replacement with the full LMP/net benefits compensation construct is based on the Commission's conclusion that when the stated conditions are met, (1) payment of compensation other than the full LMP is unjust and unreasonable, and (2) payment of LMP to demand response resources will result in just and reasonable rates for ratepayers.[11] The fallacy of the Commission's analysis of the record

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[9] Order No. 719 at P 9.

[10] *Id.* at P 8.

[11] *See* Order No. 745 at P 47.

in this proceeding is discussed in the sections below. However, at the outset, the Commission's departure from its policy of encouraging and often times mandating RTOs and ISOs to work with their stakeholders in achieving market design is arbitrary and capricious because the Commission failed to articulate a satisfactory explanation for its action.[12] Moreover, Order No. 745 does not constitute reasoned decision making because it does not offer any reason whatsoever for eliminating the ability for the RTO/ISO stakeholder processes to arrive at just and reasonable compensation mechanism for demand response, nor has the Commission explained why all RTOs and ISOs must have the same mechanism.

On this issue, Joint Parties agree with Commissioner Spitzer that "the regulatory outcome mandated herein precludes other potential outcomes arising from RTO/ISO stakeholder processes",[13] and that this is "one particularly challenging aspect of [Order No. 745] as a matter of law."[14] Joint Parties also agree with

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[12] *See, e.g., Motor Vehicle Mfrs. Ass'n of U.S. v. State Farm Mut. Auto Ins. Co.*, 463 U.S. 29, 43 (1983) (court must ensure that FERC has provided a satisfactory explanation for its action, including a rational connection between the facts found and the choice made); *Hatch v. FERC*, 654 F.2d at 834; 5 U.S.C. § 706(2)(A)(2006) ("An agency decision must not be upheld if it is arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with the law.").

[13] Statement of Commissioner Marc Spitzer on Market-Based Demand Response Compensation Rule, issued in this proceeding on March 17, 2011.

[14] *Id.*

Commissioner Spitzer that regulatory finality may be as important as regional diversity. However, regulatory finality and regional diversity need not be mutually exclusive. The Commission has in other instances provided principles or parameters for market design and could have done that here, with the promise that the Commission would impose its own compensation mechanism if the individual RTOs/ISOs and their stakeholders are unable to reach consensus. While the process might have involved an additional step, the benefit of accommodating regional differences and stakeholder input outweighs a rush to adopt an unreasonable compensation mechanism in the name of regulatory certainty.

Indeed, the sole mention of "stakeholder" in the Final Rule is in the Commission's discussion of the new net benefits test. On that issue, the Commission recounted that participants at the technical conference in this proceeding agreed that "it would be counterproductive to defer to the RTO or ISO stakeholder process to determine when demand response provides net benefits without explicit guidance from the Commission."[15] Of course, a prescribed net benefits test as imposed in the Final Rule is far more than mere "guidance." Further, Order No. 745 makes no mention of comments during the technical conference as well as written comments urging FERC to allow for regional differences and stakeholder-involved pro-

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[15] *Id.* at P 83.

posals.[16] In this respect, the Order No. 745 fails the requirement of reasoned decision-making.[17] That the

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[16] *See* Comments of [APPA] and [NRECA] filed in this proceeding on March 16, 2011 at 11 ("APPA and NRECA support allowing local and regional differences to be reflected in pricing rules in RTO-run markets. In general, demand response rules in RTO-run markets have evolved to meet specific needs. Local and regional conditions largely determine what form and what compensation level for demand response is appropriate. The availability of particular resources in a particular regional can meant that different compensation levels are needed to optimize the development of demand response. Varying consumer load profiles and retail market structures dictate that different compensation levels are appropriate in different RTO-run markets."); Tr. of the September 13, 2010 Technical Conference in this proceeding at 14, 15, comments of John Keene on behalf of the New England Conference of Public Utility Commissioners ("NECPUC") ("Regional stakeholder forums are better suited for assessing regional characteristics and determining which mechanisms are most appropriate for each region.' " Although we do not recommend prescribing a standard Net Benefits test, the Commission should provide guidance for establishing such a test. To that end, the Commission should consider objectives of a Net Benefits test that should guide formation of regional tests."); Comments of the New York Independent System Operator, Inc., in this proceeding ("NY ISO Comments") at 8 ("As well, demand response compensation needs to be integrated with these existing rules and designs to avoid unintended consequences. As a general matter, market rules have evolved based upon specific RTO/ISO needs (e.g., prevalence of combustion turbine technology, penetration of wind power, interest of alternative supply resources such as limited energy storage devices). Specific rules act together in market designs to simultaneously address these needs. If, the Commission cannot support LMP-G, it should instead require each RTO/ISO to address the issue of appropriate compensation individually."); Comments of Con-

stakeholder process might be contentious is nothing new, the Commission has dealt with such possibilities in the past by simply directing the RTO or ISO to work with stakeholders to develop a compliance filing that meets the Commission's principles or guidance, and to file its own proposal if consensus cannot be reached.[18]

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solidated Edison Solutions, Inc. and Consolidated Edison Energy, Inc., filed in this proceeding on May 13, 2010 at 4 ("While in general CES and CEE would oppose a Commission order requiring all ISOs and RTOs to compensate demand response programs at the full LMP for energy reductions, there is good cause to allow regional variations where ISOs and RTOs can propose targeted incentives to demand response providers."); Comments of the California Independent System Operator Corporation, filed in this proceeding on May 13, 2010 at 15 ("The Commission should enable regional differences to exist concerning the compensation of demand response resources as agreed to by the ISO or RTO, its stakeholders, and the relevant retail regulatory authority.").

[17] *See Northern States Power Co. v FERC*, 30 F.3d. 177, 180 (D.C. Cir. 1994) (citing *Town of Norwood v. FERC*, 962 F.2d. 20, 222 (D.C. Cir. 1992) (FERC is required to be able to demonstrate that it has "made a reasoned decision based upon substantial evidence in the record."); *NorAm Gas Transmission Co. v. FERC*, 148 F.3d. 1158, 1165 (D.C. Cir. 1998) (FERC cannot ignore arguments raised before it); *KN Energy Inc. v. FERC*, 968 F.2d 1295, 1303 (D.C. Cir. 1992) (agency must engage the arguments raised before it).

[18] *See, e.g., Midwest Independent System Operator Corporation, Inc.*, 122 FERC ¶ 61,283 (2008) at P 179 (the Commission clarified that "We clarify that in the event stakeholders cannot agree on provisions, we direct the Midwest ISO to file financial settlement/enforcement provisions based on stakeholder feedback, whether or not full consensus was possible.)

The Commission has not offered any explanation why such a process would not be feasible here.

The Commission also erred in failing to consider record evidence regarding the different types of demand response products, and/or other differences among the regions, and whether such differences dictate a regional approach to demand response compensation. The Commission is obligated to consider all evidence put forth, and provide its reasoning based on same.[19] In the Final Rule, the Commission barely acknowledges such concerns and then dismisses them by placing the onus on commenters to demonstrate that those differences matter.[20] Having received record evidence that all demand response resources are not created equal, the Commission should have at least reconsidered the presumption that compensating demand response resources at the full LMP provides "equivalent compensation for equivalent service."[21]

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[19] *See* cases cited in footnote 17, *supra*.

[20] Order No. 745 at P 67 ("Some commenters argue that the Commission should not impose a single pricing rule due to differences in market structure, state regulatory environment, and resource mix among ISOs and RTOs. While such differences may exist, the commenters have not shown why such differences warrant a different compensation level among the ISOs and RTOs.").

[21] *See* Transcript of the September 13, 2010 Technical Conference in this proceeding, at pages 7-8 (Chairman Wellinghoff opened the conference with the statement that "the presumption here is that there should be equivalent compensation for equivalent services, and that's where the Commission started here. We started giving full LMP to Demand Response for bidding into these markets.").

The lack of reasoning in Order No. 745 on this critical issue is an error that must be corrected on rehearing. Given that Order No. 745 summarily deems all compensation other than full LMP under FERC-approved tariffs unjust and unreasonable, the Commission must at least provide some analysis of the differences among products and regions as put forth by parties, in order to demonstrate that existing compensation methods are unjust and unreasonable.[22] Indeed, the only real acknowledgement that demand response resources are different and, therefore, a single compensation mechanism is unreasonable, is in Commissioner Moeller's dissenting statement where he aptly recognized that "[a]s an initial matter, RTOs and ISOs currently offer different types of demand response products that vary from region to region and in terms of capability and services offered in the day-ahead and real-time energy markets"[23] and that "[d]ifferent demand response products will have different values that reflect their vary-

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[22] *See* Post-Technical Conference Comments of the Electric Power Supply Association ("EPSA"), filed in this proceeding on October 10, 2010 at 9 (among the issues that need to be addressed by the Commission on the record with an opportunity for comment, EPSA identified the failure of the Commission's proposed tariff language to "differentiat[e] between specific types of DR products (not just any reduction from expected levels as in the NOPR) based on differing technical capabilities such as time of use limitations and response/ramping times.").

[23] Order No. 745, Commissioner Moeller's dissenting statement ("Moeller Dissent") at 1.

ing capabilities and to require a standard payment fails to reflect these meaningful differences."[24]

B. The Commission Failed to Engage in Reasoned Decision-making by Adopting a Compensation Mechanism Without Explaining How the Mechanism Will Address The Identified Barriers to Demand Response

Order No. 745 cites several barriers to demand response participation in wholesale markets, including the following: (1) regulatory and technological barriers; (2) lack of a direct connection between wholesale and retail prices; (3) lack of dynamic retail prices; (4) lack of real-time information sharing; (5) lack of market incentives to invest in enabling technologies that would allow electric customers and aggregators of retail customers to see and respond to changes in marginal costs of providing electrical service; and (6) inadequate compensation mechanisms to induce sufficient investment in demand response resource infrastructure and expertise.[25] In a single sentence and

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[24] *Id.* at 2, citing Comments of the California Public Utilities Commission, filed May 6, 2010 in this proceeding at page 6 wherein the CPUC expresses concern that "one size fits all pricing may stifle national and regional efforts to collect valuable data and experience regarding the effects of different demand response program designs on consumer participation and conflict with Congressional objectives."

[25] Order No. 745 at P 57; *see also* NOPR at note 46:

> A recent Commission Staff report details several barriers to demand response, including regulatory barriers, such as lack of a direct con-

without any explanation whatsoever, the Commission "concludes that paying LMP can address the identified barriers to potential demand response providers"[26] and then proceeds to discuss the benefits of removing those barriers.[27]

Assuming for present purposes that the identified barriers to demand response participation in wholesale markets exist, and that removing barriers to demand response participation can produce benefits, the Commission in Order No. 745 fails to even attempt to demonstrate how this full-LMP compensation mandate will address the identified barriers. As Commissioner Moeller recognized in his dissent, Order No. 745 "never clearly explains how the existence of barriers, in turn, justifies a payment of full LMP to demand re-

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nection between wholesale and retail prices, lack of dynamic prices, measurement and verification challenges, lack of real-time information sharing, and ineffective demand response program design; technological barriers, such as lack of advanced metering infrastructure and the high cost of some enabling technologies; and other barriers, such as lack of customer awareness and education. Federal Energy Regulatory Commission Staff, A National Assessment of Demand Response Potential (June 2009), found at http://www.ferc.gov/legal/staff-reports/06-09-demand-response.pdf. In compliance filings submitted by RTOs and ISOs and their market monitors pursuant to Order No. 719, as well as in responsive pleadings, parties have mentioned additional barriers, such as the inability of demand response resources to set LMP, minimum size requirements, and others.

[26] Order No. 745 at P 58.

[27] *Id.* at P 59.

sources"[28] and "does not sufficiently discus the need for standardizing compensation across the organized markets or elaborate on how standardization will remove genuine barriers that prevent meaningful participation by demand resources in the energy markets."[29]

At bottom, the full-LMP mandate provides demand response resources a payment of revenues that is greater than the value of the resource decision not to consume.[30] The Commission offers no analysis of how these higher-than-reasonable revenues will address the identified barriers to demand response. Moreover, in leap-frogging beyond the need to demonstrate some nexus between the problem identified and the action taken, the Commission overlooks comments that the full-LMP compensation will actually hamper development of demand response resources.[31] The Com-

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[28] Order No. 745, Moeller Dissent at 2.

[29] *Id.*

[30] *See* ODEC's NOPR Comments at 14 ("The NOPR proposal to pay retail demand response participants full LMP overcompensates demand resources and is akin to paying a generator full LMP plus fuel costs. This is because the cost of the retail rate component associated with generation, "G", is analogous to the fuel costs for a generator. The retail rate customer saves the cost of G or, in other words, avoids paying G, by not consuming. This is an economic benefit to the customer. If the customer then gets paid full LMP, the total benefit to the retail customer is LMP plus G."

[31] *See, e.g.*, NY ISO Comments at 3 ("The approach to the payment for demand response providers that is set forth in the NOPR, requiring ISOs/RTOs to pay LMP without reflecting the virtual re-

mission's failure to identify the connection between the facts found with respect to barriers to demand response, and the decision to compensate all demand response resources at full LMP, constitutes a failure to engage in reasoned decision making which must be corrected on rehearing.[32]

C. The Commission Erred by Ignoring Record Evidence that Demand Response Resources are Not Comparable to Generation Resources

Order No. 745 mandates that demand response resources participating in organized markets must be compensated at the full LMP when the following two conditions are met: (1) the demand response resources has the capability to provide the service, *i.e.*, the resource must be able to displace a generation resource in a manner that serves the RTO or ISO in balancing supply and demand, and (2) the payment of LMP to the demand response resource is cost-effective, per the FERC-prescribed net benefits test.[33]

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tail purchase of the commodity being sold at wholesale, will slow the introduction of other innovative clean technologies by uneconomically suppressing real-time prices without any guarantee that the overpayment inherent in such a rate will foster further investment rather than act as a mere windfall.").

[32] *See Burlington Truck Lines v. United States*, 371 U.S. 156, 168 (1962) ("The agency must articulate a 'rational connection between the facts found and the choice made.'").

[33] Order No. 745 at P 48.

On the first element of the test for full-LMP compensation, the Commission apparently concludes that demand response resources are comparable to generation resources in terms of balancing supply and demand and, therefore, should be compensated at the full LMP in the same manner as generation resources.[34] In so doing, the Commission erred by overlooking and failing to address record evidence that demand response resources are not comparable to generation, even for the balancing of supply and demand upon which the Order No. 745 full-LMP compensation mandate is based.[35] In those instances where demand response resources are not comparable to generation, the Commission has provided no basis for demand response and generation resources to receive the same compensation, and such compensation is unjust and unreasonable.[36]

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[34] *See id.* at P 119 (the Commission explains that Order No. 745 addresses "compensation to demand response resources on a comparable basis to supply-side resources when demand response resources are comparable to supply-side resources, so that both supply and demand can meaningfully participate.").

[35] See cases cited in footnote 17, *supra*.

[36] *See* Comments of the American Public Power Association and the National Rural Electric Cooperative Association, filed in this proceeding on May 13, 2010, at 12-13 ("It is not unjust and unreasonable to treat demand response resources differently than generators and other suppliers. By analogy to Order No. 890, demand response, generation and transmission are to be treated 'comparably', but it does not follow that each of them is "the same" and therefore must be compensated in the same manner.").

In its comments on the NOPR in this proceeding, ODEC demonstrated that demand response resources are not comparable to generation because, among other things, (1) in some cases demand response resources have less stringent performance requirements than generation resources, including the absence of penalties for no performance by demand response resources and difference in the applicability of market power mitigation rules; and (2) generation resources have the core business function of supplying electricity for load consumption which makes them more likely to be an available resource in an enduring fashion, while demand response resources do not have any such imperative to serve as a resource. As ODEC explained, these differences can directly impact the availability and certainty that demand response resources will reduce consumption when called upon.[37] Generation resources, on the other hand, are subject to stringent penalties for failure to perform and operate for the

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[37] *See* ODEC NOPR Comments at 10, noting that in PJM, the rules under which demand response resources operate create disparities between generation resources and demand resources. While generation resources are dispatched by system operators, demand response is "a voluntary reduction in electric consumption in response to price and to the end-use facility operational needs, such as an industrial customer needing to immediately complete a production run to fulfill a customer order. The amount of load reduction is determined by the responder and can vary from hour to hour in PJM's program. There is no potential cost penalty for demand resources if they choose not to curtail, and a responder's curtailment decision is generally made without consideration of the grid's operation and stability."

purpose of providing electricity, so there is greater certainty that generators will be available for dispatch when called upon. Others have similarly demonstrated that demand response and generation resources are not comparable in terms of economics and reliability.

Rather than meaningfully address these concerns by taking them into account in its mandate that all demand response resources be compensated at the full LMP, the Commission simply "agrees as a general matter that demand response providers and generators should be subject to comparable rules that reflect the characteristics of the resources, and expect ISOs and RTOs to continue their evaluation of their existing rules in light of this Final Rule and make appropriate filings with the Commission."[38] The comparability of demand response resources and generation resources is critical to the Commission's determination that the two should be compensated at the same rate. Order No. 745's cursory treatment of this issue, without any resolution or even a substantive discussion of why the resources should be treated the same for purposes of compensation despite record evidence to the contrary, is far from sufficient to meet the obligation that the Commission explain the basis for its decision.[39]

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[38] Order No. 745 at P 66.

[39] *See Northern States Power Co. v FERC*, 30 F.3d. 177, 180 (D.C. Cir. 1994) (citing *Town of Norwood v. FERC*, 962 F.2d. 20, 222 (D.C. Cir. 1992) (FERC is required to be able to demonstrate that

D. The Commission Failed to Establish that the Full-LMP Compensation Mandate will Produce Rates that are Just, Reasonable, and Not Unduly Discriminatory or Preferential

Order No. 745 determines that when the capability and net benefits standards are met, payment of the full LMP to demand response resources will result in just and reasonable rates for ratepayers.[40] For all of the reasons discussed above, the Commission's mandatory full-LMP compensation for all RTOs and ISOs is unjust and unreasonable. Additionally, by failing to reflect in demand response resource compensation the avoided cost that demand response providers will enjoy by reducing consumption, Order No. 745 will result in rates that are unjust and unreasonable.

Several commenters, including ODEC, demonstrated that if a standardized demand response compensation mechanism is to be required, then LMP minus "G" is the just and reasonable compensation level. As explained by ODEC:

> The NOPR proposal to pay retail demand response participants full LMP over-compensates demand resources and is akin to paying a generator full LMP plus fuel costs. This is because the cost of the retail rate component associated with generation, "G", is analogous to the fuel costs for a gener-

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it has "made a reasoned decision based upon substantial evidence in the record.");

[40] Order No. 745 at P 47.

> ator. The retail rate customer saves the cost of G or, in other words, avoids paying G, by not consuming. This is an economic benefit to the customer. If the customer then gets paid full LMP, the total benefit to the retail customer is LMP plus G.

ODEC NOPR Comments at 14. Commissioner Moeller correctly surmised that while FERC's intent might have been sound, the implementation is not. As explained in Commissioner Moeller's dissent to Order No. 745, requiring demand resources to be paid the full LMP, as opposed to the value of full LMP, results in a "'double-payment' because the resources would 'receive' both the cost savings from not consuming electricity at a particular price, plus an LMP payment for not consuming that same increment of electricity. Not only is this result not comparable and economically inefficient. , but this preferential compensation will harm the efficiency of the competitive wholesale energy markets."[41] Moreover, the Commission's refusal to reflect in compensation the fact "that the demand resources will retain the retail rate ("G") as part of the provider's total compensation" is not supported by the record. Indeed, the Commission recognized that demand resources will retain the "G", but nevertheless refuses to take it into account for compensation purposes claiming "practical difficul-

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[41] Moeller Dissent at 5, quoting Dr. William W. Hogan, Attachment to Answer of EPSA filed on October 29, 2009 in Docket No. EL09-68.

ties.[42]" As noted in Commissioner Moeller's Dissent, such claims are unfounded given that several state commissions, as well as ISOs and RTOs, have indicated that ignorance of the retail rate will yield uneconomic outcomes, and none has claimed that it would be difficult to subtract the retail rate (G) from the LMP payment.

Order No. 745 rejects concerns regarding overcompensation. However, the Commission's reasons are incorrect and do not justify imposition of compensation for demand response resources that is greater than the compensation provided to even the generation resources which the Commission points to for support. First, the Commission is wrong in its reasoning that full LMP payment to demand response resources (which amounts to LMP + G) is justified because "demand resources participating in the organized wholesale energy markets can be cost-effective for balancing supply and demand and, in those circumstances, it follows that the demand response resource should also receive compensation at LMP."[43] Even assuming the Commission's assertions of the cost-effectiveness of demand resources are correct, as discussed above and in Commissioner Moeller's dissent, the LMP minus G compensation methodology does provide the demand response resource "compensation at LMP" as the Commission intends. The full-LMP

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[42] Order No. 745 at P 63.

[43] *Id.* at P 61.

compensation, however, provides compensation beyond LMP because it would require the demand response resource "receive" LMP plus the avoided generation cost. Second, the Commission's reference to "market imperfections" and the determination in Order No. 719 that favors allowing demand response to bid into organized markets does nothing to justify over-compensation for demand response resources. The Commission has not identified any reason why the cited benefits[44] of allowing demand response to bid into organized wholesale energy markets cannot be achieved with the just and reasonable compensation of LMP minus G as opposed to LMP plus G, and Joint Parties believe there are none. Third, the Commission's reliance on Dr. Kahn's argument that paying demand response the full LMP does not result in over-compensation ignores direct record evidence to the contrary. As has been demonstrated by several commenters in this proceeding, and through the example in Commissioner Moeller's dissent, compensating demand response resources at full LMP results in over-compensation and creates an unreasonable subsidy for demand response resources. As Robert L. Borlick

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[44] Order No. 745 at P 61 (the Commission cites to Order No. 719 which recognizes that allowing demand response to bid into organized markets "expands the amount of resources available to the market, increases competition, helps reduce prices to consumers and enhances reliability." (citation omitted).

explained in his response to Dr. Kahn, filed in this proceeding on October 12, 2010:[45]

> The problem arises because the retail customers providing demand response are compensated not only by the direct payments they receive but also by their bill savings from avoiding payment through their retail tariffs The sum of the two which includes the demand response providers' bill savings, comprise the demand response providers' total compensation. In this example the total compensation exceeds the generators' cost savings, which means that the economic value of the foregone energy (as measured by the products and services it could have produced for the load curtailing retail customers) may also exceed those cost savings. If so, economic efficiency suffers and society would be better off if the demand response had never occurred.
>
> The optimum price to pay for demand response is that which maximizes this difference between the production costs saved and the economic value lost through foregone consumption. If demand response is compensated beyond that point, the lost economic value of the foregone energy will increase faster than the generators' production costs decline until the point is reached where all of the economic

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[45] Response of Robert L. Borlick to Professor Alfred E. Kahn, filed in Docket Nos. RM10-17, *et al.* on October 12, 2010 ("Borlick Response").

> gains achievable through optimal demand response pricing are wiped out. Further increases in the price paid for demand response will produce net economic losses, making everyone (except for the overcompensated demand response providers) worse off than if the wholesale demand response program never existed. This is a very real threat posed by the current NOPR rule.

Borlick Response at 9-10. The "current NOPR rule" referenced by Mr. Borlick is the Commission's proposal to "pay[] demand response providers full LMP, with no offsetting reduction for the payments they avoid under their retail tariffs",[46] which is the compensation mandated by Order No. 745. Order No. 745 makes no recognition or rebuttal to this demonstration that paying demand response LMP indeed results in compensation that is beyond competitive levels. As such, Order No. 745 does not constitute reasoned decision-making.[47]

Finally, the Commission's full-LMP mandate is arbitrary and capricious because it fails to address concerns regarding the adverse impact that the compensation mechanism will have on load-serving entities ("LSEs"), particularly not-for-profit LSEs, such as the Joint Parties' members. As APPA explained in its post-technical conference comments in this proceeding, not-for-profit LSEs providing bundled electric

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[46] *Id.* at 6.

[47] *See* cases cited in footnote 17, *supra*.

service pursuant to an obligation to serve all customers in their service territories incur substantial costs to provide such service.[48] When retail customers on these LSEs' systems decide in the short-term to reduce their energy-related demand in order to receive demand response compensation, the LSE will likely retain the obligation to stand ready to serve the customers' full load because the industrial/large commercial customers engaging in compensated demand reductions have no obligation to reduce energy demand but instead have the option to do so when it is in their economic interest.[49] In those instances, the LSE is left to decide not only how to account for such possible load reductions in its power supply planning, but may also be left to pay for the maintenance of its ability to meet the full demand, per its load-serving obligation.[50] The Final Rule does nothing to avoid this adverse impact of the mandatory full-LMP and net benefits test. The Final Rule does not take into account the cost to LSEs of both paying the full LMP for demand response resources, and incurring the cost to stand ready to meet their load-serving obligations.

For all of the reasons stated in Sections IV.A. through D above, Order No. 745 erred in mandating that every RTO and ISO provide full-LMP compensation to all demand response resources that pass the

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[48] APPA Post Technical Conference Comments at 8.

[49] *Id.*

[50] *Id.* at 9.

capability and net benefits tests, and the Commission's directive does not reflect reasoned decision-making. Therefore, on the compensation issue, Joint Parties request that the Commission grant rehearing and either direct each individual RTO and ISO to work with its stakeholders and propose the appropriate compensation for demand response resources or, in the alternative, adopt the LMP minus G compensation for demand response resources participating in ISO/RTO markets.

E. The Net Benefits Test Does Not Remedy the Deficiencies of the Full-LMP Mandate

In order to determine the threshold price when "it is cost-effective to pay full LMP to demand resources"[51], the Commission directs each RTO and ISO to perform a prescribed net benefits analysis, on a monthly basis based on historical data and the previous year's supply curve. Second, Order No. 745 requires each RTO and ISO to undertake a study examining the requirements and impacts of implementing a dynamic approach to determine the threshold price when paying demand response resources LMP results in net benefits to consumers.[52]

At the outset, there is no need for any sort of net benefits test as the basis for full-LMP compensation because the full-LMP compensation is unjust and

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[51] Order No. 745 at P 79.

[52] *Id.* at P 84.

unreasonable for all of the reasons discussed above.[53] Moreover, the Commission's own statements establish that the net benefits test cannot remedy the fact that the full-LMP compensation will result in rates that are unjust and unreasonable. The stated purpose of the net benefits test is to determine when the reduction in prices resulting from reduced consumption outweigh the billing unit effect. In those instances, the Commission believes that paying demand response the full LMP is cost-effective. However, the Commission explicitly states in Order No. 745 that "the threshold price approach we adopt here may result in instances both when demand response is not paid the LPM but would be cost-effective and when demand response is paid the LMP but is not cost effective."[54] Despite the fact that the Commission's own calculation method fails to protect load from paying full LMP to demand response resources even when such reliance on demand response is not cost-effective, the Commission "accept[s] this result given the apparent computational difficulty of adopting a dynamic approach that incorporates the billing unit effect in the dispatch algorithms at this time."[55] The very standard for full

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[53] If the Commission adopts the LMP minus G compensation, no such net benefits test would be necessary because the net benefit to customers, which is the difference between the LMP and what they would have paid under the retail rate, is reflected in the compensation. *See* Commissioner Moeller's Dissent at 7 (citations omitted).

[54] *Id.* at P 80.

[55] *Id.*

LMP is that "the Commission finds that when a DR resource participating in an organized wholesale market is capable of balancing supply and demand in the energy market and is cost-effective, as determined by the net benefits test described herein, that DR resource should receive the same compensation, LMP, as a generation resource with dispatched."[56] Yet, the Commission admits that its test will result in DR being dispatched and paid LMP when it is not cost-effective. The Commission cannot reasonably adopt a test for the purpose of ensuring that load only pays for demand response resources as an alternative to generation with such dispatch is cost- effective, in full recognition that the test does not serve that purpose. The fact that the Commission is also directing RTOs and ISOs to develop a net benefits measurement construct that will supersede the method it is ordering them to use initially is a tacit acknowledgement that the "interim" test is flawed. Since it is, the RTOs should not be required to use it. The Commission's failure to engage in reasoned decision-making renders its decision to adopt the new net benefits test arbitrary and capricious.[57]

Further, the Commission's net benefits test does not resolve concerns that such a test would be difficult and costly to administer. As Andy Ott of PJM stated

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[56] *Id.* at P 82 (emphasis added).

[57] *See Moraine Pipeline Co. v. FERC*, 906 F.3d 5, 8 (D.C. Cir. 1990); *Canadian Ass'n of Petroleum Producers v. FERC*, 254 F.3d 289, 299 (D.C. Cir. 2001).

during the technical conference in this proceeding, "an iterative process to look at impacts on market price, m opinion is that would be very costly and difficult to do, if we could even do it."[58] In requiring compliance filings for the monthly net benefits test as well as the study of a dynamic process, the Commission does not consider or resolve whether the test is feasible for implementation or, for that matter, whether the cost and burden on RTOs/ISOs of complying with this aspect of the Rule is reasonable. Every indication from the record in this proceeding is that development of a "net benefits" methodology will be very difficult, if not impossible, to do. And given that the "net benefits" test is, in essence, a "fig leaf"[59] that attempts unsuccessfully to redress the fatal flaws in a full LMP compensation method, RTOs should not be required to devote substantial resources to developing such a methodology.[60]

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[58] September 13, 2010 Technical Conference Transcript at 82; *see also* Commissioner Moeller's dissent at 6-7.

[59] Moeller Dissent at 6.

[60] *See* Request for Clarification of the Illinois Commerce Commission, filed in this proceeding on April 13, 2011. In its request, the Illinois Commerce Commission ("ICC") demonstrates that the net benefits test is unclear, difficult to administer, and could result in unjust and unreasonable rates. The following are among the questions and issues raised in the ICC's request: (1) Will demand response resources be dispatched when LMP is less than the cost effective price level in the static model? If so, what level of compensation will RTO/ISOs pay to demand response resources when LMP is below the threshold?; (2) That when demand response is

F. The Cost Allocation Mandate of Order No. 745 Is Ill-Defined

Order No. 745 determines that costs for demand response compensation should be allocated "proportionally to all entities that purchase from the relevant energy market in the area(s) where the demand response reduces the market price for energy at the time when the demand response resource is committed or dispatched."[61] The Final Rule requires each RTO and ISO to make a compliance filing by July 21, 2001,[62] that either demonstrates that its current cost allocation methodology appropriately allocates costs to ben-

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dispatched below the threshold and paid something less than LMP, then it needs to be cost effective at that level of compensation; (3) Will the cost effective price level in the static model be determined by considering demand response offers individually, in aggregate, or by some other means?; (4) Which demand response resources receive LMP compensation when multiple demand response resources clear in the static model?; (5) That the cost effectiveness test does not need to be incorporated into the dispatch algorithm; and (6) How uncertainty in the level of compensation under the dynamic model's cost effectiveness test might undermine the implementation of such a model?

[61] Order No. 745 at P 102.

[62] Joint Parties note that the compliance filings on cost allocation are due by July 21, 2011 (Order No. 745 at P 102), while the net benefits test compliance filings are due by July 22, 2011. *Id.* at P 81. Given the related nature of these aspects of the Final Rule, Joint Parties believe efficiency would be better achieved by requiring a single compliance filing to address both aspects of the Rule. However, Joint Parties do not seek rehearing of the compliance dates.

eficiaries, or proposes revised tariff provisions to meet this requirement.

Here again, Order No. 745 fails to engage in reasoned decision-making because the Commission does not explain why any alternative cost allocation mechanisms for demand response compensation that are currently on file with the Commission are unjust and unreasonable.[63] Instead, the Commission simply requires each RTO and ISO to adopt the Commission's cost allocation mechanism, or prove that theirs is appropriate. Moreover, the references to "all entities" that must fund the demand response compensation, as well as the "area(s)" subject to paying for the demand response compensation, are not defined in Order No. 745. Does the Commission intend that all entities in the relevant area, even those providing the demand response resources, should share in the payments for same? Order No. 745 implies but does not explicitly state whether the areas for cost allocation must follow the designation of LMPs. Presumably, such issues can be resolved through the compliance filing process but to the extent Order No. 745 mandates a particular result, the Rule is not sufficiently clear and the Com-

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[63] *See* 16 U.S.C. § 824e; *Louisiana Pub. Serv. Commission v. System Energy Resources, Inc., et al.*, 124 FERC ¶ 61,003 (2008); *See Northern States Power Co. v FERC*, 30 F.3d. 177, 180 (D.C. Cir. 1994) (citing *Town of Norwood v. FERC*, 962 F.2d. 20, 222 (D.C. Cir. 1992) (FERC is required to be able to demonstrate that it has "made a reasoned decision based upon substantial evidence in the record.").

mission should clarify that it will address these issues on a case-by-case basis in the compliance process.

V. CONCLUSION

WHEREFORE, for the foregoing reasons, Joint Parties respectfully request that the Commission: (1) grant this request for rehearing; and either (2) direct each individual RTO and ISO to work with its stakeholders and propose the appropriate compensation for demand response resources and test for when such resources should be dispatched instead of generation resources, if necessary; or (3) adopt the LMP minus G compensation and forego the net benefit test. Joint Parties also request that the Commission clarify that it will address application of the cost allocation requirements on a case-by-case basis.

Respectfully submitted,

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Dated: Apr. 14, 2011

UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. RM10-17-000

DEMAND RESPONSE COMPENSATION IN ORGANIZED WHOLESALE ENERGY MARKETS

Apr. 14, 2011

REQUEST FOR REHEARING OF THE EDISON ELECTRIC INSTITUTE

Pursuant to Section 313 of the Federal Power Act and Rule 713[1] of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or "Commission"), the Edison Electric Institute ("EEI") requests rehearing of the Commission's Final Rule on Demand Response Compensation in Organized Wholesale Energy Markets.[2]

EEI is the association of U.S. shareholder-owned electric companies. EEI's members serve 95 percent of the ultimate customers in the shareholder-owned segment of the industry, and they represent approxi-

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[1] 18 C.F.R. § 385.713 (2008).

[2] *Demand Response Compensation in Organized Wholesale Energy Markets*, 134 FERC ¶ 61,187, Order No. 745 (March 15, 2011) ("Order No. 745" or "Final Rule").

mately 70 percent of the U.S. electric power industry. EEI's diverse membership includes utilities operating in all regions, including regions with RTOs and ISOs.

EEI and its members strongly support the participation of demand response in wholesale and retail markets and recognize the benefits provided to the markets by Demand Response Resources. Many of our members have robust demand response programs at the retail level and have worked closely with their customers and state commissions to successfully develop and implement these programs. In addition to these retail programs, EEI members that have voluntarily joined RTOs and ISOs have customers participating in demand response programs in the organized wholesale markets either individually or through aggregators of retail customers ("ARC"). These EEI members have supported demand response programs in organized markets and in providing reasonable and appropriate compensation for service provided.

While EEI and its members recognize and support the role that demand response plays in the organized wholesale markets, EEI is concerned that the Commission's decision to pay Demand Response Providers the full Locational Marginal Price ("LMP"), in all RTO and ISO regions without adjustment for the retail price saved, constitutes an unduly preferential payment for demand resources over other resources.[3]

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[3] California's investor-owned utilities believe that this undue preference can be overcome by a retail settlement between retail

EEI's concerns on this issue are not alleviated by the Commission's decision to allow LMP payments only when its net benefits test is satisfied, rather than at all hours as proposed in the Notice of Proposed Rulemaking.[4] EEI appreciates that the Commission tried to accommodate some of its concerns arising from paying demand resources full LMP by including the net benefits test, which limits the hours during which this payment is made. However, as explained below, inclusion of the net benefits test does not address EEI's basic concern that payment of full LMP overcompensates demand resources and EEI's concern that the Commission is mandating this approach on all RTOs and ISOs.

On behalf of its member companies, EEI respectfully seeks rehearing of the Commission's order and requests that the Commission reconsider and modify its Final Rule in this docket. Specifically, EEI requests that the Commission allow each individual RTO and ISO to determine its market rules for effectively compensating Demand Response Resources.

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customers, load serving entities and demand response providers associated with demand response participation in wholesale markets, but support allowing ISOs/RTOs to voluntarily take on such responsibilities. *See* Joint Comments of San Diego Gas & Electric Company, Southern California Edison Company, Pacific Gas and Electric Company, May 13, 2010. Many of EEI's members are unable, for a variety of legal or practical reasons, to rely on their local regulatory authority to implement a retail settlement process.

[4] *Demand Response Compensation in Organized Wholesale Energy Markets*, 75 Fed. Reg. 15362 (Mar. 29, 2010) ("NOPR").

I. BACKGROUND

On March 18, 2010 the Commission issued a NOPR in which the Commission requested comments on its proposal to amend Chapter I, Title 18, Section 35.28 of the Code of Federal Regulations by adding a new paragraph (g)(l)(v) which would state that "each Commission-approved ISO and RTO that has a tariff provision providing for participation of Demand Response Resources in its energy market must pay Demand Response Resources, in all hours, the market price for energy, i.e., full LMP, for demand reductions made in response to price signals."[5] In May 2010, EEI and more than 100 other parties submitted comments in response to the NOPR.

In August the Commission issued a Supplemental NOPR that modified the original proposed rule by requiring the payment of full LMP for demand response only in those hours when such payments are determined to be "cost-effective" through application of a "net benefits" test. The Commission also held a technical conference on September 13, 2010, which focused on the need for, and the nature of, such a net benefits test and also on the methodology ISOs or RTOs should use to recover the costs of purchasing demand response.

On March 15, 2011 the Commission issued its Final Rule, Order No. 745. The Final Rule requires each

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[5] NOPR at P 11.

Commission-approved ISO or RTO that has a tariff provision permitting demand response to participate as a resource in the energy market by reducing consumption of electric energy from their expected levels in response to price signals, to:

(A) pay to those demand response resources the market price for energy for these reductions when these demand response resources have the capability to balance supply and demand and when payment of the market price for energy to these resources is cost-effective as determined by a net benefits test accepted by the Commission;

(B) allocate the costs associated with demand response compensation proportionally to all entities that purchase from the relevant energy market in the area(s) where the demand response reduces the market price for energy at the time when the demand response resource is committed or dispatched.[6]

EEI seeks rehearing of this Final Rule.

II. STATEMENT OF ISSUES AND SPECIFICATIONS OF ERROR

In accordance with 18 C.F.R. § 385.713(c)(1) and (2), EEI respectfully requests rehearing of the Order with respect to the following issues and specifications of error:

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[6] Order No. 745, Regulatory Text, at p. 97.

a. Whether the Commission erred by failing to specify whether existing demand response compensation programs in RTOs and ISOs are no longer just and reasonable, or whether they remain in effect. Existing tariffs on file under Section 205 of the Federal Power Act are just and reasonable and the Commission lacks the authority to nullify them absent a clear finding to the contrary. Federal Power Act Sections 205, 206, 16 U.S.C. §§ 824d, 824e; *Atlantic City Electric v. FERC*, 295 F,3d 1 (D.C. Cir. 2002) (*"Atlantic City"*); *FPC v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956); *United Gas Pipe Line Co. v. Mobile Gas Serv. Corp.*, 350 U.S. 332 (1956) (*"Mobile"*).

b. Whether the Commission engaged in reasoned decision-making based on substantial evidence in the record, in concluding that Demand Response Resources must be paid the LMP for reductions in energy withdrawals or whether it acted in a manner that was arbitrary and capricious. *See Williams Gas Processing-Gulf Coast Co., L.P., et al. v. FERC*, 2006 U.S. App. EXIS 31127 (D.C. Cir. 2006) ("[w]e must vacate FERC's 2005 orders if they are arbitrary and capricious. We therefore look to whether FERC articulated a rational explanation for its action." *See also, Missouri PSC v. FERC*, 234 F.3d 36, 41 (D.C. Cir. 2000) ("A passing reference is not sufficient to

satisfy the Commission's obligation to carry out reasoned and principled decision-making. We have repeatedly required the Commission to fully articulate the basis for its decision.") (Internal quotation marks omitted). *See also, Motor Vehicle Mfrs. Ass'n of the U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (Order is arbitrary and capricious where agency fails to provide reasoned basis for its decision, and departure from precedent.).

c. Whether the Commission's mandated cost allocation methodology departs from well-established precedent and principle that costs be allocated in proportion to the benefits received without sufficient explanation or justification. *See, e.g.,Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1368, 1370-71 (D.C. Cir. 2004); *see* also *Illinois Commerce Commission v. FERC*, 576 F.3d 470, 476 (7th Cir. 2009).

III. REQUEST FOR REHEARING

EEI seeks rehearing of the Commission's finding to require RTOs and ISOs to compensate Demand Response Resources at full LMP and to recover these payments through energy surcharges imposed on wholesale buyers.

A. The Commission Did Not Meet its Burden Under Sections 205 and 206 of the Federal Power.

The Final Rule makes no finding on the record submitted and provides no explanation of whether and how the Final Rule impact existing ISO and RTO demand response compensation rules and tariff provisions on file with the Commission, which are presumed to be just and reasonable. In failing to make this finding, the Commission did not comply with FPA Sections 205 and 206. In *Atlantic City*, the court held that public utilities retain the right to file rates or charges under FPA section 205. The Commission may review those rates or charges under section 206, but it can "reject them only if it finds that the changes proposed by the public utility are not 'just and reasonable.'"[7] The court explained:

> Section 205 (and 206) of the Act "are simply parts of a single statutory scheme under which all rates are *established initially* by the [public utilities], by contract or otherwise, and all rates are subject to being modified by the Commission upon a finding that they are unlawful."[8]
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> Section 206 merely permits the Commission—acting either on its own initiative or after a complaint—to initiate changes to *existing* utility

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[7] *Atlantic City Electric Co* at 9 (citing *Cities of Campbell v. FERC*, 770 F.2d 1180, 1184-85 (D.C. Cir. 1985); *Papago Tribal Util. Auth. v. FERC*, 723 F.2d 950, 952-53 (D.C. Cir. 1983).

[8] *Atlantic City* at 10 (citing *Mobile* at 341).

rates and practices. In order to make any change in an existing rate or practice, FERC must first prove that the existing rates or practices are "unjust, unreasonable, unduly discriminatory or preferential." 16 U.S.C. § 824e(a); *see Alabama Power Co. v. FERC*, 993 F.2d 1557, 1569 (D.C. Cir. 1993). Then FERC must show that its proposed changes are just and reasonable. *Tennessee Gas Pipeline Co. v. FERC*, 860 F 2d 446, 454 (D.C. Cir. 1988).[9]

The Final Rule fails to comply with these requirements. In the NOPR, the Commission acknowledges that it has "issued orders in recent years approving various types of ISO and RTO demand response programs."[10] Under currently filed tariffs, Demand Response Resources may participate as energy resources in the day-ahead and real-time energy markets in PJM, NYISO, ISO New England, CAISO and MISO.[11] The NOPR recognizes that RTOs and ISOs have continued to examine the effectiveness of demand response compensation in their respective regions, and the issue of compensation continues to be the subject of several proceedings at the Commission.[12]

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[9] *Id.* at 10.

[10] NOPR at P 7.

[11] NOPR at P 8. Order No. 745 at P 14.

[12] *Id.*

The Commission stated in the NOPR that it is:

> now concerned that evidence of demand reductions in PJM, and inadequate demand response participation, now and in the future, may be the result of compensation that is no longer just and reasonable, because, as detailed below, the existing and varying levels of compensation generally fail to reflect the marginal value of demand resources to ISO and RTO energy markets.[13]

Having accepted as just and reasonable the tariff provisions addressing demand response compensation filed by ISOs and RTOs, the Commission is under the obligation to clarify how Order No. 745, and the record in this proceeding, affect these prior determinations, if at all, and to explain why these tariff provisions are now unjust and unreasonable as required by Section 206. The Commission has failed to meet its burdens under Section 206 to do this and therefore the basis of the Commission's holding in the Final Rule is deficient under the FPA.

In the Final Rule, the Commission finds that compensating Demand Response Resources at LMP "is necessary to ensure that rates are just and reasonable in the organized wholesale energy markets."[14] After reviewing the demand response compensation proposals it has already approved and the procedural

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[13] *Id.* at P 10.

[14] Order No. 745 at P 2.

history of the proceedings in this docket, the Commission concludes that: "Based on the record in this proceeding, the Commission herein requires greater uniformity in compensating Demand Response Resources participating in organized wholesale energy markets."[15]

This summary conclusion is not sufficient to pass muster under *Atlantic City* and other cases similarly requiring that the Commission find that an existing rate on file is not just and reasonable before imposing a different scheme. While the Commission discusses its view of why it believes requiring the payment of full LMP to Demand Response Resources is the preferred option, it never makes the required finding (or any finding) that the tariffs addressing demand response compensation on file, and approved for each of the ISOs and RTOs, are unjust and unreasonable. There can be more than one rate design that is just and reasonable. The Commission has failed to articulate any basis to support a finding that the demand response compensation proposal it adopted in the Final Rule is the preferred one-size-fits-all approach to a multi-faced issue for all the RTOs and ISOs or that previously approved demand response compensation rules are no longer just and reasonable. Instead, the Final Rule seems to offer only a conclusion that it prefers greater uniformity and the approach adopted in the Final Rule. In doing so, the Commission has acted in

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[15] *Id.* at P 17.

contravention of FPA sections 205 and 206 and should grant rehearing.

B. The Commission's Decision Requiring All ISOs and RTOs to Pay Demand Response Resources LMP is Not Supported by Substantial Evidence and Does Not Constitute Reasoned Decision-making.

The record in this proceeding (which also incorporates the record established in Docket No. EL09-68-000[16]) contains the testimony of numerous experts with extensive knowledge of the economics underlying the electric power industry which weigh heavily in opposition to the Commission's proposal.[17] In addi-

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[16] PJM Interconnection, L.L.C., Docket No. EL09-68-000 (August 31, 2009); NOPR at P 23.

[17] *See e.g.* the following comments filed in response to the NOPR, on May 13, 2010: Dr. William Hogan; Raymond Plank Professor of Global Energy Policy, John F. Kennedy School of Government, Harvard University; Dr. David Patton, Potomac Economics, Inc. Independent Market Monitor, Midwest ISO, ISO-NE, New York ISO and ERCOT; Dr. Joseph Bowring, Monitoring Analytics, LLC, PJM Independent Market Monitor; Mr. David LePlante, Vice President—Market Monitoring, ISO-NE; Dr. Hung-Po Chao, Director, Market Strategy and Analysis, ISO-NE. Mr. Robert L. Borlick, Energy Consultant, advisor to the Midwest ISO; Dr. Roy Shanker, Energy Consultant, advisor to the NEPGA; Dr. Robert Ethier, Vice President, ISO-NE. Dr. Sam Newell, Principal, The Brattle Group, Inc; Dr. Philip Q Hanser, Principal, The Brattle Group, Inc.; Dr. Kathleen Spees, Associate, The Brattle Group, Inc.; Dr. David P. Chassin, Battelle Pacific Northwest National Laboratory; Dr. Lynne Kiesling, Kellogg School of Management, Northwestern University; Dr. Michael Giberson, Center for Ener-

tion to these experts, the Commission also did not address the comments submitted by the Federal Trade Commission, which also opposes payment of full LMP to demand resources.[18] Despite this record, in making its finding requiring all RTOs and ISOs to pay full LMP, the Commission relies primarily on the testimony of Professor Emeritus Alfred Kahn. The Commission does not explain why it summarily rejected the arguments and positions of other experts and does not address why it chose to accept Professor Kahn's opinion over the unified position of the other experts. By failing to substantively address these arguments, the Commission's decision to mandate full LMP compensation for Demand Response Resources in all RTOs and ISOs is arbitrary and capricious as the Commission failed to provide a rational basis for its decision.[19]

There is substantial evidence in the record that payment of full LMP to Demand Response Resources is unduly preferential and unjust and unreasonable because it results in overcompensation to Demand Re-

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gy Commerce, Texas Tech University; Mr. Jeffrey D. Tranen, Senior Vice President, Compass Lexicon and Mr. Constantine. P. Gonatas, CPG Advisors, Inc.

[18] Comment of the Federal Trade Commission, Docket No. RM10-17-000 at 6-7 (May 13, 2010).

[19] *See e.g. Williams Gas Processing-Gulf Coast Co., L.P., et al. v. FERC*, 2006 U.S. App. LEXIS 31127 (D.C. Cir. 2006); *Missouri PSC v. FERC*, 234 F.3d 36, 41 (D.C. Cir. 2000); *Motor Vehicle Mfrs. Ass'n of the U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983).

sponse Resources and causes market inefficiencies.[20] As a result of this evidence, as more fully explained

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[20] See *e.g.* the following comments in response to the NOPR submitted on May 13, 2010: ISO New England Inc. at 17; New York Independent System Operator, Inc. at 11-4 ("NY ISO"); PJM Interconnection, L.L.C. at 6-8 ("PJM"); Midwest Independent Transmission System Operator, Inc. at 6-7 ("MISO"); Southwest Power Pool, Inc. at 3; ISO New England Inc. Internal Market Monitor at 4-5; Independent Market Monitor for PJM at 3-7; Potomac Economics, LTD at 6-9; Illinois Commerce Commission at 8-13; Public Utilities Commission of Ohio at 3-4; Organization of MISO States at 3; Edison Electric Institute at 15-18; Hogan, William W., Demand Response Pricing in Organized Wholesale Markets, White Paper submitted by the ISO RTO Counsel at 3-5; Borlick, Robert L. at 7 and Attachment A at 2-3; Samuel Newell, Kathleen Spees and Philip Q Hanser, The Brattle Group at 8; David P. Chassin, Lynne Kiesling, and Michael Giberson, at 2; CPG Advisors, Inc. at 11; New England Power Generators Association (Affidavit of Roy J. Shanker) at 2-3; American Electric Service Corporation ("AEP") at 9. San Diego Gas & Electric Company, Southern California Edison Company and Pacific Gas and Electric Company, at 3; Consolidated Edison Solutions, Inc. and Consolidated Edison Energy, Inc. at 2-4; Consumers Energy Company at 2-3; Detroit Edison Company at 3-4; Dominion Resources Services, Inc. at 5-6; Duke Energy Corporation at 2-3; Northeast Utilities Service Company at 4; PPL Parties at 7, 12; PSEG Companies, at 7-8; Midwest TDUS at 11-12; Calpine Corporation, at 3; International Power Corporation at 2; PJM Power Providers Group (Affidavit of Jeffrey Tranen at P 5.); RRI Energy, Inc. at 3; Independent Power Producers of New York, Inc. at 3; GDF Suez Energy North America at 2; Mirant Corporation at 2; Exelon Corporation at 3; Capital Power Corporation at 6; Indicated New York Transmission Owners at 4-5; Midwest ISO Transmission Owners at 4-5; American Public Power Association and the National Rural Elec-

below, the Commission should not mandate a demand response compensation mechanism and should allow individual RTOs and ISOs, through their stakeholder process, to determine the compensation mechanism that works best for their market structure and the needs in their region.[21] By failing to address these arguments, the Commission failed to engage in reasoned decision-making supported by substantial evidence.

1. Demand Response Providers Currently Receive Compensation that is Comparable to Other Energy Resources.

Commissioner Moeller indicates in his dissent that " the concept of comparability is at the core of this rulemaking. "[22] The Commission asserts that payment of LMP is appropriate because a megawatt-hour of load reduction is equal to a megawatt- hour of increased generation for purposes of

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tric Cooperative Association at 13. See *also* Old Dominion Electric Cooperative at 14 (May 14, 2010).

See also Comments of the Independent Market Monitor for PJM, Docket No. EL 09-68-000, at 5-7 (October 16, 2009); Hogan, William, W., Providing Incentives for Efficient Demand Response, White Paper submitted by EPSA in Docket No. EL09-68-000 at 13-18 (October 30, 2009).

[21] For example, currently MISO and PJM effectively pay Demand Response Resources LMP-G and NY ISO pays full LMP with a base line.

[22] Order No. 745, Dissent of Commissioner Moeller at 3 ("Moeller dissent").

balancing system supply and demand.[23] EEI agrees that the concept of comparability must be and is at the core of this rulemaking.

While generation and demand response do not provide the same services to the markets, demand response plays an important role in the marketplace and is compensated on a basis comparable to other energy resources. Through the RTO and ISO stakeholder process, EEI members have supported paying demand resources comparably to generation resources. Paying demand response LMP minus the marginal retail energy rate (or LMP-"G") is comparable to paying generation resources LMP.

Demand response is the decision not to consume energy. The Commission recognizes this in its regulations when it defines demand response as "a reduction in the consumption of electric energy by customers from their expected consumption in response to an increase in the price of electric energy or to incentive payments designed to induce lower consumption of electric energy."[24] By choosing not to consume energy or purchase energy, the customer saves money by not paying the retail rate for the energy not consumed or purchased. This is G. For example, most retail customers are served through tariffs that grant the customer the right to purchase electric energy at a fixed price. By selling its demand reduction to an

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[23] Order No. 745 at PP 54-55.

[24] 18 C.F.R. § 35.28(b)(5) (2010).

ARC participating as a Demand Response Resource in the wholesale market, the retail customer is actually selling its property right to consume energy at its fixed tariff price. The Demand Response Resource, in turn, resells that right to the ISO or RTO. In the parlance of finance theory this property right is a "call option" with a "strike price" equal to the fixed energy price in the customer's retail tariff. This concept was introduced by a number of parties to the NOPR proceeding—including Professor Kahn.[25] While Professor Kahn agrees with viewing demand response as a call option, he failed to follow through on the necessary logic of that view, which is that a customer selling its call option to consume should be paid the market value of that option—not the market value of the foregone energy.

The value of a call option at the time of its expiration is equal to the market price of the underlying commodity less the option's strike price. This implies that the market value of one MWh of demand response is equal to: (LMP—marginal retail energy rate or

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[25] See *e.g.*, the following comments submitted on May 13, 2010 in response to the NOPR: The Edison Electric Institute at 16; Potomac Economics, Ltd at 5; MISO at 6-7; Robert L. Borlick at 7; The New England Power Generators Association (Affidavit of Roy Shanker at 16-18).

See *e.g.*, Reply Comments to NOPR: Demand Response Supporters, Kahn Affidavit at 22 (August 30, 2010); Response of Robert L. Borlick to Professor Alfred E. Kahn, at 2 (October 8, 2010) ("Borlick Response"); Borlick, Robert L., "Pricing Negawatts," *Public Utilities Fortnightly* at 14 (August 2010).

G).[26] Consequently, this is the economic price for the ISO or RTO to pay to Demand Response Resources. Furthermore, paying LMP-G for demand response provides total compensation equal to LMP for the retail customer providing the demand response.[27] This is the same net level of compensation that generation resources receive for providing energy at the same location on the transmission system where the demand response is delivered.

The Commission does not discuss the concept that demand response is a call option other than making passing reference to it.[28] It also asserts that demand response is not a sale of energy.[29] However, the Commission fails to address the argument, made by several experts in this proceeding, that the demand response a retail customer sells is effectively the sale of its right to purchase and consume electricity at the marginal energy rate in its retail tariff and that this should be recognized in the compensation mechanism. In fail-

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[26] Retail customers are served through tariffs employing fixed energy prices. In reality these tariffs typically contain price schedules that discontinuously change with consumption levels, i.e. they contain two or more pricing "blocks." The marginal retail energy rate is the fixed price for energy consumed in the block within which the customer curtails its consumption to provide the demand response.

[27] If a retail customer is participating in the wholesale markets though an ARC, then the ARC may retain a portion of this amount.

[28] Order No. 745 at P 24.

[29] *Id.* at P 64.

ing to address these concepts, the Commission has failed to apply reasoned decision making. Moreover, the Commission has undermined its own concept of comparability as further explained in Section C.

2. Paying Full LMP Over-Compensates Demand Response, Reducing Economic Efficiency.

Under the rule established by the Commission, a Demand Response Resource participating in the wholesale market benefits not only from the payment received for the demand response but also by not having to pay for the energy it curtailed. This means that the customer receives more than LMP for its curtailments. This overpayment distorts market signals and creates economic inefficiency, as ISOs and RTOs will *overprocure* demand response because the market no longer provides a signal to the consumer as to when it is efficient for the consumer to stop consuming. Professor Hogan pointed this out, stating:

> The imputed demand response provider receives a double payment because it never purchased the electricity that the proposed rule would permit it to sell back to the RTO or ISO. As a result, under the proposed rule, it would receive the LMP for selling the imputed demand response, without having to pay for the right to consume that electricity in the first place. If it had paid for the baseline electricity, then paying the demand response provider the LMP for reductions in the amount of electricity it purchased would be entirely consistent

> with economic efficiency. But the proposed rule contains no such provisions.[30]

A number of other experts submitted similar comments regarding the existence of double compensation and its adverse impact on economic efficiency. The comments of Dr. David Patton, Independent Market Monitor for the Midwest ISO, ISO-New England, New York ISO and ERCOT, are particularly illuminating:

> We are now allowing the DR resource to sell energy in the wholesale market that it is not required to purchase at the retail rate. Hence, one can clearly see in this case that the DR resource is receiving a subsidy to curtail equal to the retail rate. This will manifest itself in potentially significant economic inefficiencies.[31]

In addition, as a result, large industrial and commercial customers served under LMP-based retail tariffs may effectively collect *twice LMP* for their demand response. That is, a retail customer that may curtail consumption in response to an LMP price signal during a peak period would get paid for doing that which they would otherwise do. They respond rationally and efficiently to a price signal and then they get paid the LMP in addition. PJM's Independent

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[30] Comments of Electric Power Supply Association, Docket No. RM10-17-000. Hogan Affidavit at 5 (May 12, 2010).

[31] Comments of Potomac Economics, Ltd. Docket No. RM10-17-000 at 7 (May 13, 2010).

Market Monitor, Joseph Bowring, recognized this in stating:

> However, the result of the proposed implementation of this policy would be that demand side participants would receive the LMP plus the avoided cost of purchasing power. For customers already paying retail rates equal to the LMP, such compensation would be twice LMP This proposal is inconsistent with fundamental economics and, if adopted by the Commission would over compensate participants in economic load response programs, negatively affect the efficient operation of the energy markets and provide no offsetting social benefit.[32]

The Commission responds to the concern that its Final Rule constitutes a subsidy for demand response by again quoting Professor Kahn:

> Does this plan involve double compensation, as [Dr.] Hogan asserts, at the expense of power generators—of successful bidders promising to induce efficient demand curtailment and of consumers induced to practice it? Certainly not: the decrease in the revenue of the generators is (and consequent savings by consumers are) matched by the savings in their (marginal) costs of generating that power; the successful bidders for the opportunity to induce that consumer response are compensated for the

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[32] Comments of Monitoring Analytics, LLC, Docket No. RM10-17-000 at 2 (May 13, 2010).

> costs of those efforts by the pool, whose (marginal) costs they save by assisting consumers to reduce their purchases.[33]

But nowhere in Order No. 745 does the Commission give consideration to any critiques of Professor Kahn's statement, such as those submitted by Robert Borlick.[34]

Finally, the Commission argues that even if paying full LMP overcompensates demand resources, it would be impractical to attempt to eliminate the subsidy component by adjusting the prices paid to Demand Response Resources to net out their customers' retail bill savings:

> In addition, we agree with the New York Commission that given the differences in retail rate structures across RTO footprints and even within individual states, requiring ISOs and RTOs to incorporate such disparate retail rates into wholesale payments to wholesale demand response providers would, even though perhaps feasible, create practical difficulties for a number of parties, including state commissions and ISOs and RTOs.[35]

This statement directly conflicts with the comments of Mr. Michael Robinson, the Midwest ISO's Senior

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[33] Order No. 745 at P 31.

[34] Borlick Response, Docket No. RM10-17-000 at 6-10 (October 8, 2010).

[35] Order No. 745 at P 63.

Manager for Markets Development who stated at the Commission's September 13, 2010 technical conference that " we have the tools in place currently to accommodate whatever the Marginal Foregone Retail Rate would be as specified by the retail regulatory authority."[36] The Midwest ISO had already filed with the Commission the tariff changes needed to implement the settlement adjustments that Michael Robinson described. The Organization of MISO States ("OMS") expressed support for the Midwest ISO proposal to adjust its demand response payments to offset the avoided payments for energy at the retail level.[37]

While overcompensating demand response, the Commission has not given due consideration to the long-term effects of its Final Rule. As EEI pointed out in its comments, consumers may benefit from lower market energy prices in the near-term but will suffer in the long-term when demand growth a: d plant retirements necessitate the entry of additional generation.[38] When that time arrives market prices will rebound to whatever levels are needed to attract new

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[36] Robinson, Demand Response Compensation in Organized Wholesale Energy Markets Technical Conference: Docket No. RM10-17-000, September 13, 2010, ("FERC Technical Conference Transcript") at 159, 203-204.

[37] Organization of MISO States, Organization of MISO States, Docket No. RM10-17-000 at 4 (May 13, 2010).

[38] Comments of Edison Electric Institute, Docket No. RM10-17-000 at 11-13 (May 13, 2010); *See also* Comments of American Electric Power, Docket No. RM10-17 at 9 (May 13, 2010).

generation investment. Consumers will have to pay those prices and additionally will have to pay for the subsidies resulting from the Commission's over-generous demand response compensation mandate.[39] Commissioner Moeller indicated a similar concern regarding long-term effects, citing the NYISO and also stating:[40]

> The long-term costs of allowing demand resources to receive preferential compensation will manifest themselves in various ways. Meanwhile, at the wholesale level, the corrosive effect of overcompensating demand resources over time will come at the expense of other resources, particularly generation resources that will have less to invest in maintaining existing facilities and financing new facilities.[41]

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[39] Double recovery may create other unintended consequences. For example, in the ISO New England Forward Capacity Market, new capacity resources may submit cost-justified bids that take into account its projected revenue recovered in other markets. Thus, the Commission's mandate in Order No. 745 may result in lower cost-justified bids by Demand Response Resources because such resources will receive double recovery in the energy markets. This in turn will undermine the intent of the Forward Capacity Market to compensate resources for providing reliability services and create an entirely new "missing money" problem.

[40] Moeller dissent at 10.

[41] Comments of NYISO, Docket No. RM10-17 at 15 (May 13, 2010), "[P]aying demand response an LMP-based payment because it is thought that demand response participation will reduce LMPs for all customers is not a sufficient rationale for justifying an

Thus, requiring ISOs and RTOs to pay twice for the same demand reduction will produce shortfalls in their revenues, giving rise to a "missing money" problem. This issue is further discussed below in Section C.

3. Paying Demand Resources Full LMP Undermines Retail Programs and Imposes Additional Costs on Non-Participating Retail Consumers.

The Commission appears to justify its Final Rule by claiming that barriers exist to demand response participation.[42] The Commission then concludes that paying LMP can address the identified barriers to potential demand response providers and is not the same as giving preferential treatment to demand response.[43] However, the Commission fails to show how the subsidies it has mandated will overcome and *exactly* offset these barriers. Commissioner Moeller recognizes this in his dissent, stating:

> This is to say that the majority believes that paying demand resources more money will help overcome these barriers and encourage more participation. The Rule, however, never clearly explains how the

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'additional payment' for a favored technology. Demand response is not the only resource able to provide such benefits. However, [other] technologies may be kept out of the market by demand response that would be uneconomic at LMP-G but participates when subsidized at LMP."

[42] Order No. 745 at P 57.

[43] *Id.* at P 58-59.

existence of barriers, in turn, justifies the payment of full LMP to demand response.[44]

Commissioner Paul Centolella, of the Ohio Public Utilities Commission, best described this issue at the technical conference:

> And I have a significant concern that we are putting a big weight on one side of the scale here of how Demand Response develops, and ignoring potential others ways in which demand could simply respond to price and develop much more efficiently.
>
> And I am concerned that we are potentially distorting innovation on the demand side of this market if what we do is selectively say we're going to pay an additional incentive to people who participate in economic RTO programs when that same incentive is not available to consumers who are simply responding to a dynamic retail price.
>
> And so I think if we're going to talk about additional incentives, we need to think about how we do this in a more neutral fashion and in a way that will potentially get us further ahead, rather than assuming the only way we're going to do this is by having an aggregator bid that into a wholesale market. Because we may be passing up even more Demand Response benefits by putting a weight on that side of the scale.[45]

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[44] Moeller dissent at 2.

[45] Centolella, FERC Technical Conference Transcript, at 232-233.

The Commission fails to address how overcompensating demand response at the wholesale level will incent the deployment of smart technology infrastructure at the retail level. One of the barriers to entry for demand response is the lack of smart technology at the retail level that allows consumers to receive more accurate price signals. The Commission does not address how requiring payment of full LMP at the wholesale level will reduce these barriers. In addition, many retail customers already participate in retail demand response programs that are integrated into the Load Serving Entity's ("LSE") integrated resource planning. The non-participation of certain loads or the change in relation of certain loads to the retail programs brought about by the wholesale LMP payments mandated in the Final Rule could undermine the effectiveness of these retail programs and have other unintended consequences that the Commission did not appear to even consider.[46]

Second, in addition to the impact on development of retail programs, the Commission did not explain how the mandate of Order No. 745 will avoid double payment for the "sale" of the same curtailed megawatt-hours (often referred to as "negawatt-hours") to the retail customer's utility as well as to the wholesale energy markets. The Commission should otherwise explain how retail consumers and loadserving entities

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[46] *See e.g.* Centolella , FERC Technical Conference Transcript at 141-142; Comments of Ohio PUC, Docket No. RM10-17-000 at 4 (May 13, 2010).

will be kept whole due to the loss of contribution to fixed costs (which occurs when a retail rate design recovers fixed costs through volumetric rates) resulting from sale of demand response in wholesale markets. The Commission must address this problem and consider the impacts on retail ratemaking when fulfilling its responsibilities to ensure that wholesale rates are just and reasonable.

Third, the Commission does not address arguments stating that paying Demand Response Resources full LMP causes cost shifting between retail customer classes. At the current time, smart metering technology is largely available only to large customers. As a result, most Demand Resource Providers are large industrial and commercial customers so the cost shifts are largely from large customers to small customers.[47] This problem will be exacerbated if overcompensating demand response at the wholesale level delays infrastructure deployment at the retail level.[48]

It is insufficient for the Commission to fail to address these issues by stating that it has no jurisdiction over retail matters and has no intent to preempt retail programs because, as stated above, the decision to

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[47] *See e.g.* Comments of PJM Independent Market Monitor, Docket No. RM10-17-000 at 8-9 (October 16, 2009, at 8-9. Moeller dissent at 5. Borlick Response at 13-14.

[48] *See e.g.* Centolella, FERC Technical Conference Transcript at 232-233, Comments of Old Dominion Electric Cooperative, Docket No. RM10-17-000 at 21-22 (May 14, 2010).

compensate demand response through wholesale markets is a decision to supplement price signals that already exist, albeit imperfectly, at the retail level. The Commission must address on rehearing how its Final Rule reconciles with, and does not undermine, existing retail demand response programs or impede the development of new programs. Reasoned agency action requires the Commission to prevent or mitigate the adverse economic consequences that Order No. 745 may have on LSEs and their residential and small business consumers that are currently unable to participate in wholesale energy markets either directly or through ARCs.

4. Payment of Full LMP to Demand Resources Results in Unjust, Unreasonable and Unduly Preferential Rates.

As previously indicated, payment of full LMP constitutes over-payment for demand response relative to that received by other resources. This generic mandate does not take into consideration the different market structures in individual RTOs and ISOs[49] and results in rates that are unjust and unreasonable. Commissioner Moeller, in his dissent recognized this and stated that the payment of LMP to demand resources effectively provides them " total com-

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[49] Some EEI members believe that paying demand response LMP as an incentive (above LMP-G) may be just and reasonable in some situations but agree that FERC should not adopt a single mandatory rule.

pensation of LMP + G. "[50] This is analogous to paying generators LMP for the energy they inject into the system plus reimbursing them for the fuel used to produce that energy. As previously explained, this disparity in treatment is even more troubling for industrial or large commercial customers that could receive a payment of twice LMP if they are on retail tariffs indexed to day-ahead or real time market LMPs—once through the direct payment for the demand response and again by avoiding payment under the retail tariff for the foregone energy.

In addition, as several commenters indicated, some large industrial or commercial customers may receive payments for "demand response" that is produced by running behind-the-meter generation ("BTMG"). For example, Severstal Steel's Sparrows Point plant purchases its electricity directly from PJM's day-ahead and real-time markets. The plant has a peak load of 230 MW and has 150 MW of BTMG that it uses to reduce its purchases when PJM's LMPs are greater than the running costs of its own generation.[51] Clearly, Severstal Steel's generators are directly competing with wholesale generators in the PJM footprint but they are being compensated exactly twice LMP for the energy that the wholesale generators can produce at half that price. Paying one generator twice the price

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[50] Moeller dissent at 4.

[51] Demand Response Supporters' Protest, Docket No. EL09-68-000, Sept. 16, 2009, Att. D (Affidavit of Ron Belbot on Behalf of Demand Response Supporters) at 1-2.

that is paid to another generator for delivering an identical, fungible product is clearly unduly discriminatory. Furthermore, such a practice is not selling demand reductions; it is selling energy from an alternate source of generation.

The Commission's Final Rule requiring payment of full LMP constitutes unduly preferential treatment for demand response relative to generation. It directly conflicts with the Commission's own Order No. 719 and with the Federal Power Act's prohibition against undue discrimination.

C. The Commission's Cost Allocation Methodology Violates the Principle of Assigning Costs in Proportion to Benefits Received.

The additional payment made to Demand Response Resources must be recovered by the ISOs and RTOs. The Commission has adopted the simplest way to recover these costs, which is through a surcharge on all energy in the hour the shortfall occurred.[52] This approach is flawed in two ways. First, it produces cross-subsidies among the wholesale buyers (see example in Table 1), thereby misapplying the judicially-endorsed cost causation principle of assigning costs in proportion to the benefits received. As articulated by the Commission in *Northern States Power Company*, "[t]he *fundamental* theory of Commission ratemaking is that costs should be recovered in the rates of those

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[52] Order No. 745 at P 100.

customers who utilize the facilities and thus cause the cost to be incurred."[53] The D.C. Circuit echoed this sentiment in *KN Energy, Inc. v. FERC*, "[s]imply put, it has been traditionally required that all approved rates reflect to some degree the costs actually caused by the customer who must pay them."[54] Second, it thwarts the ability of retail regulatory authorities to offset the inefficient wholesale pricing at the retail level because the cross-subsidies are broadly spread over LSE and retail jurisdictional boundaries.

A numerical example demonstrates how the Commission has misapplied this established cost causation principle (see Table 1).

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[53] 64 FERC P 61,324 at *13 (1993) (emphasis supplied); *see also Mansfield Municipal Electric Department v. New England Power Company*, 97 FERC P 61,134 at 61,615 (2001) (same, citing *Northern States*).

[54] 968 F.2d 1295, 1300 (D.C. Cir. 1992); see also *Alcoa Inc. v. FERC*, 564 F.3d 1342, 1346 (D.C. Cir. 2009); *Illinois Commerce Commission v. FERC*, 576 F.3d 470, 476 (7th Cir 2009); *Public Service Commission of Wisconsin v. FERC*, 545 F.3d 1058, 1067 (D.C. Cir. 2008); *Pacific Gas & Electric Company v. FERC*, 373 F.3d 1315, 1320 (D.C. Cir. 2004).

Table 1—DR Payment Recovery with Order 745 Allocation Methodology No Transmission Congestion

Load Serving Entity	A	B	C	D	E	Total
Gross Load – before DR (MW)	1,000	1,000	1,000	1,000	1,000	5,000
DR Response (MW)	110	10	10	10	10	150
Net Load – after DR (MW)	890	990	990	990	990	4,850
LMP – before DR ($/MWh)	$110	$110	$110	$110	$110	$110
LMP – after DR ($/MWh)	$100	$100	$100	$100	$100	$100
Payments for DR ($000)	$11,000	$1,000	$1,000	$1,000	$1,000	$15,000
Payment Recovery Surcharge ($/MWh)	$3.09	$3.09	$3.09	$3.09	$3.09	$3.09
Energy Price with Surcharge ($/MWh)	$103.09	$103.09	$103.09	$103.09	$103.09	$103.09
LSE's Avoided Loss on Retail Sales ($000)	$6,600	$600	$600	$600	$600	$9,000
Savings from Lower LMP ($000)	$8,910	$990	$990	$990	$990	$12,870
Total Benefit before Surcharge ($000)	$15,550	$1,590	$1,590	$1,590	$1,590	$21,870
Share of Total Benefits (Percent)	71.1%	7.3%	7.3%	7.3%	7.3%	100%
Payment Recovery from Surcharge ($000)	($2,750)	($959)	($959)	($959)	($959)	($6,870)
Share of the DR Payments (Percent)	18.4%	20.4%	20.4%	20.4%	20.4%	100%
1 Assumes the marginal retail energy rate is $50 MWh for all LSEs						

Assume there are five LSEs in an energy market, all with zonal loads of 1,000 MW in the hour and that no transmission congestion exists. The retail customers of one LSE (A) deliver 110 MW of demand response in that hour while the retail customers of each of the other LSEs deliver only 10 MW each. This causes the hourly LMP to drop from $110/MWh to $100/MWh.

The ISO purchases the demand response at a total cost of $15,000 [150 MWh * $100/MWh] and recovers this cost through an energy uplift surcharge of $3.09/MWh [$15,000/(5000 - 150) MWh]. Thus, each LSE is paying $103.09 for each MWh (including the surcharge), which is less than the $110/MWh, it would have paid absent the demand response. LSE A receives most of the demand response benefits by not

having to purchase 110 MWh at $110/MWh and reselling it at retail for $50/MWh, thereby avoiding a loss of $6,600 [110 MWh * ($110 $50)]. In addition, this LSE benefits from purchasing 890 MWh at $100/MWh (excluding the surcharge charge) rather than paying $110/MWh, thereby saving an additional $8,900 [890 MWh * ($110-$100)]. Thus, this LSE's total benefit from the demand response is **$15,500.** In contrast, each of the other LSEs save only $600 in avoided losses [10 MWh * ($110-$50)] while gaining a benefit of $9,900 [990MWh * ($110 $100)] from the lower LMP. Thus, the total benefit of each of these LSEs is **$10,500**, i.e., about two-thirds as much as the first LSE. However, the surcharge established by the net benefits test allocates to each of these LSEs **$3,059** [990 MWh * $3.09] in demand response payment recovery, while the first LSE is only allocated **$2,750** [890 MWh * $3.09] even though it receives benefits from demand response that are almost 50 percent larger.

Thus, although simplified, this example demonstrates that the Commission's cost allocation methodology does not allocate the costs in proportion to benefits received, thereby violating the cost causation principle. Because the Commission's net benefits test ensures that no wholesale buyer is made worse off than it would have been if the demand response did not occur, these cross-subsidies are effectively hidden.

The Commission's cost allocation methodology also fails to account for the complexities that can arise from

transmission congestion. Although it correctly allocates the costs of demand response payment recovery to wholesale buyers within transmission-congested areas, it overlooks the reality that demand response can relieve congestion, thereby changing the boundaries of one or more transmission-congested area(s). When this occurs the benefits that each wholesale buyer enjoys due to the demand response must be calculated through computer simulation of the counterfactual (no demand response) case, then compared with the actual case. Allocating recovery of the demand response payments in proportion to wholesale buyers' benefits will then be complex and cannot be accomplished through the Commission's rule.

A second example (Table 2) illustrates the impact of demand response when transmission congestion exists.

Table 2—DR Payment Recovery with Order 745 Allocation Methodology Transmission Congestion Present

Load Serving Entity	A	B	C	D	E
Gross Load – before DR (MW)	1,000	1,000	1,000	1,000	1,000
DR Response (MW)	110	10	10	10	10
Net Load – after DR (MW)	890	990	990	990	990
LMP – before DR ($/MWh)	$110	$110	$90	$120	$121
Energy Component of LMP ($/MWh)	$109	$109	$109	$109	$109
Loss Component of LMP ($/MWh)	$1	$1	$1	$1	$2
Congestion Component of LMP	$0	$0	($20)	$10	$10
LMP – after DR ($/MWh) ($/MWh)	$100	$100	$100	$100	$100
Energy Component of LMP ($/MWh)	$99	$99	$99	$99	$99
Loss Component of LMP ($/MWh)	$1	$1	$1	$1	$1
Congestion Component of LMP	$0	$0	$0	$0	$0
Payments for DR ($000)	$11,000	$1,000	$1,000	$1,000	$1,000
Payment Recovery Surcharge ($/MWh)	$3.09	$3.09	$3.09	$3.09	$3.09
Energy Price with Surcharge ($/MWh)	$103.09	$103.09	$103.09	$103.09	$103.09
LSE's Avoided Loss on Retail Sales ($000)[1]	$6,600	$600	$400	$700	$710
Savings from Lower LMP ($000)	$8,900	$9,900	($9,900)	$19,800	$20,790
Total Benefit before Surcharge ($000)	$15,500	$10,500	($9,500)	$20,500	$21,500
Share of Total Benefits (Percent)	26.5%	17.9%	(16.2)%	35.0%	36.8%
Payment Recovery from Surcharge ($000)	($2,750)	($3,059)	($3,059)	($3,059)	($3,059)
Share of the DR Payments (Percent)	18.4%	20.4%	20.4%	20.4%	20.4%
1 Assumes the marginal retail energy rate is $50/MWh for all LSEs					

The first three rows in Table 2 are the same as those in Table 1 but the LMPs in row four are now different because of the transmission congestion and transmission losses that would exist if the demand response did not occur. This is the counterfactual case. The rest of the table entries are the same as in Table 1 except for those related to the benefits derived by the LSEs (rows 15 through 18). These benefits vary substan-

tially from those shown in Table 1, which was a no transmission congestion case. The last two columns differ only because demand response also reduces the transmission losses in Subregion E.

What is particularly important is that demand response may not produce benefits for all consumers, as demonstrated by the *loss* that LSE C incurs, in the example above, due to the increased LMP it will face after demand response relieves transmission congestion. Presumably the Commission's net benefits test can preclude this but that test will have to be very complex. This example indicates that the Commission has failed to give cost allocation the thorough consideration it deserves.

There is a more efficient, equitable way to allocate ISO or RTO payments for demand response: the bifurcated methodology that PJM and ISO-NE recommended in their comments.[55] The Commission dismissed this methodology, arguing that it appears to represent an arbitrary division of cost responsibility without regard to the degree to which each receives benefits.[56] Nonetheless, EEI believes that this methodology more logically adheres to the cost causation principle than the approach endorsed by the Commission. To illustrate this, EEI has applied the bifur-

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[55] Comments of PJM, Docket No. RM10-17-000 at 12 (May 13, 2010); Comments of ISO-NE, Docket No. RM10-17-000 at 5 (May 13, 2010).

[56] Order No. 745 at P 101.

cated methodology to the example shown above in Table 1 (see Table 3).

Table 3—DR Payment Recovery with Bifurcated Cost Allocation Methodology No Transmission Congestion

Load Serving Entity	A	B	C	D	E	Total
Gross Load – before DR (MW)	1,000	1,000	1,000	1,000	1,000	5,000
DR Response (MW)	110	10	10	10	10	150
Net Load – after DR (MW)	890	990	990	990	990	4,850
LMP – before DR ($ MWh)	$110	$110	$110	$110	$110	$110
LMP – after DR ($ MWh)	$100	$100	$100	$100	$100	$100
Payments for DR ($000)	$11,000	$1,000	$1,000	$1,000	$1,000	$15,000
Payment Recovered from LSE ($000)	$5,500	$500	$500	$500	$500	$7,500
Payment Recovery Surcharge ($ MWh)	$1.55	$1.55	$1.55	$1.55	$1.55	$1.55
Energy Price with Surcharge ($ MWh)	$101.55	$101.55	$101.55	$101.55	$101.55	$101.55
LSE's Avoided Loss on Retail Sales ($000)[1]	$6,600	$600	$600	$600	$600	$9,000
LSE's Avoided Loss Recaptured ($000)	($5,500)	($500)	($500)	($500)	($500)	($7,500)
Savings from Lower LMP ($000)	$8,900	$9,900	$9,900	$9,900	$9,900	$48,500
Total Benefit before Surcharge ($000)	$10,000	$10,000	$10,000	$10,000	$10,000	$50,000
Share of Total Benefits (Percent)	20.0%	20.0%	20.0%	20.0%	20.0%	100%
Payment Recovery from Surcharge ($000)	$1,376	$1,531	$1,531	$1,531	$1,531	($7,500)
Share of the DR Payments (Percent)	18.4%	20.4%	20.4%	20.4%	20.4%	100%
1 Assumes the marginal retail energy rate is $50 MWh for all LSEs						

The first six rows in Table 3 are identical to those in Table 1. The seventh row is new and displays the components of the DR payment that are targeted for direct recovery from the LSEs. Each component is equal to the LSE's loss on retail sales that it avoids due to the demand response delivered by its retail customers at the actually realized LMP of $100/MWh. Consistent with the cost causation principle, this targeted cost allocation directly recaptures the benefit the LSE would otherwise enjoy by not having to de-

liver at a loss the energy its retail customers curtailed. The residual DR payments remaining after such recaptures are then recovered through the energy surcharge, just as in the previous example. Note, however, that the surcharge is now much smaller and would be zero if the payments for demand response had occurred at the economically efficient price of LMP minus each demand response provider's marginal retail energy rate.

As shown in Table 3, the benefit that each LSE derives from demand response is the same for each LSE—as it should be since they all start out with the same gross load. Comparing the share of the total benefits each LSE receives with the share of the costs it pays through the surcharge, it becomes apparent that all LSEs bear almost the same proportion of the costs as the benefits they receive, assuming there is no transmission congestion. This differs markedly from the result the Commission's methodology will produce, as shown in Table 1.

Unfortunately, even the bifurcated cost recovery methodology does not equitably allocate costs when transmission congestion exists and is significantly relieved by demand response. The example in Table 4 illustrates this. However, this problem would not occur if the price paid for demand response were LMP minus the marginal energy rate in the demand response providers' retail tariffs. In that case there would be no residual payments to recover, thus no need for an energy surcharge, and no cross-subsidies.

The cross-subsidies created by the Commission's cost allocation methodology effectively disconnect LSE payments for purchased energy from the payments their respective retail customers enjoy by providing the demand response. Although retail regulators may be able to recapture the payments to these retail customers, *e.g.*, by charging them for their curtailed energy at their respective tariff rates (if state law allows), doing so will not make their LSEs indifferent because of the cross-subsidies that the Commission's Final Rule will produce.

Table 4—DR Payment Recovery with Bifurcated Cost Allocation Methodology Transmission Congestion Present

Load Serving Entity	A	B	C	D	E
Gross Load – before DR (MW)	1,000	1,000	1,000	1,000	1,000
DR Response (MW)	110	10	10	10	10
Net Load – after DR (MW)	890	990	990	990	990
LMP – before DR ($/MWh)	$110	$110	$90	$120	$121
Energy Component of LMP ($/MWh)	$109	$109	$109	$109	$109
Loss Component of LMP ($/MWh)	$1	$1	$1	$1	$2
Congestion Component of LMP	$0	$0	($20)	$10	$10
LMP – after DR ($/MWh) ($/MWh)	$100	$100	$100	$100	$100
Energy Component of LMP ($/MWh)	$99	$99	$99	$99	$99
Loss Component of LMP ($/MWh)	$1	$1	$1	$1	$1
Congestion Component of LMP	$0	$0	$0	$0	$0
Payment for DR ($000)	$11,000	$1,000	$1,000	$1,000	$1,000
Payment Recovered from LSE ($000)	$5,500	$500	$500	$500	$500
Payment Recovery Surcharge ($/MWh)	$3.09	$3.09	$3.09	$3.09	$3.09
Energy Price with Surcharge ($/MWh)	$1.55	$1.55	$1.55	$1.55	$1.55
LSE's Avoided Loss on Retail Sales ($000)[1]	$6,600	$600	$400	$700	$710
LSE's Avoided Loss Recaptured ($000)	($5,500)	($500)	($500)	($500)	($500)
Savings from Lower LMP ($000)	$8,900	$9,900	($9,900)	$19,800	$20,790
Total Benefit before Surcharge ($000)	$10,000	$10,000	($10,000)	$20,000	$21,000
Share of Total Benefits (Percent)	19.6%	19.6%	(19.6)%	39.2%	41.2%
Payment Recovery from Surcharge ($000)	$1,376	$1,531	$1,531	$1,531	$1,531
Share of the DR Payments (Percent)	18.4%	20.4%	20.4%	20.4%	20.4%
1. Assumes the marginal retail energy rate is $50/MWh for all LSEs					

For this reason the California Public Utilities Commission ("CPUC") has requested clarification of the impact that the Commission's proposed rule would have on the CPUC's proposed Proxy Demand Re-

sponse Product.[57] The CPUC Proxy Demand Product would require ARCs representing retail customers of California's investor-owned utilities to compensate those utilities for their lost retail revenues.[58]

Finally the, previously described, "missing money" problem can be resolved in an economically efficient manner if the ISO or RTO employs its settlements system to net out the demand response providers' avoided retail payments from the LMP payments made to their respective Demand Response Resources. The ISO or RTO can then charge the net payments back to the LSE whose retail customers produced the demand response the ISO or RTO purchased from the Demand Response Resource. This is the methodology the Midwest ISO proposed in its Order 719 compliance filing, which was supported by the OMS, the Independent Market Monitor, EEI and a number of LSEs.[59]

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[57] Notice of Intervention, Comments and Request for Clarification of the Public Utilities Commission of the State of California Regarding the Proposed Rulemaking on Demand Response Compensation in Organized Wholesale Energy Markets, Docket No. RM10-17-000 at 9-10 (May 13, 2010).

[58] California Independent System Operator, Tariff Amendment to Implement Proxy Demand Response Product, Docket No. ER10-765-000 at 12-13 (February 16, 2010).

[59] Midwest Independent Transmission System Operator Inc., Filing re Aggregators of Retail Customers, Docket No. ER09-049-002 at 13-16 (October 2, 2009); Organization of MISO States, Docket No. RM10-17-000 at 6 (May 13, 2010); Comments of Edison Electric Institute, Docket No. RM10-17-000 at 18 (May 13, 2010); Potomac Economics, Docket No. RM10-17-000 at 9 (May 13, 2010)..

V. CONCLUSION

For the reasons stated above, EEI respectfully requests that the Commission grant rehearing as requested herein.

Respectfully submitted

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Apr. 14, 2011

Consumers Energy, Docket No. RM10-17-000 at 2-3 (May 13, 2010); Comments of Detroit Edison, Docket No. RM10-17-000 at 4 (May 13, 2010); Midwest TDUS, Docket No. RM10-17-000 at 11-12 (May 13, 2010).

UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. RM10-17-001

DEMAND RESPONSE COMPENSATION IN ORGANIZED
WHOLESALE ENERGY MARKETS

Apr. 14, 2011

REQUEST FOR REHEARING OF THE COMPETITIVE POWER SUPPLIER ASSOCIATIONS

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Table of Contents

I. STATEMENT OF ISSUES AND ERRORS.....[1128]

II. BACKGROUND.....[1138]

A. The NOPR.....[1138]

B. The Final Rule.....[1140]

C. Commissioner Moeller's Dissent.....[1142]

III. REQUEST FOR REHEARING.....[1146]

A. The Final Rule Is Contrary To Law And Arbitrary And Capricious Because It Mandates Unduly Preferential Treatment Of DR Resources And Undue Discrimination Against Generators.....[1147]

1. DR Resources And Generation Are Not "Equivalent," Nor Do They Have The Same Marginal Value.....[1149]

2. DR Resources Are Not Comparable And Are Not Entitled To The "Same" Compensation As Generators, Much Less The Unduly Preferential Compensation Required By The Final Rule.....[1155]

3. The Commission's Decision Is Arbitrary And Capricious Because It Fails To Address Serious Objections That Its Proposed Approach Is Unduly Preferential And Unduly Discriminatory.....[1160]

B. The Commission's Determination That The Final Rule Is Necessary To Make ISO/RTO Rates Just And Reasonable Is Contrary To Law, Arbitrary And Capricious, And Not Supported By Substantial Evidence.....[1161]

1. The Final Rule Is Based On Numerous Erroneous And/Or Unsupported Assumptions And Policy Judgments .....[1165]

2. The Commission Has Failed To Establish That The Final Rule Will Produce Just And Reasonable Rates Or To Respond To Objections Concerning The Detrimental Impacts Of The Final Rule.....[1179]

3. The Final Rule Departs Without Adequate Explanation From Existing Precedent That Subsidies Are Not Necessary To Incent DR Participation.....[1190]

4. The Commission's Determination That The Final Rule Is Necessary To Ensure That ISO/RTO Rates Are Just And Reasonable Is Contrary To Law Because It Ignores Regulated Sellers' Statutory And Constitutional Rights To Just And Reasonable Compensation .....[1191]

5. To The Extent The Commission Found That Existing ISO/RTO Mitigation Is Inadequate, Its Determination Is Arbitrary And Capricious, Unsupported By Substantial Evidence, And Contrary To Law.....[1197]

6. The Perceived Need For A Net Benefits Test Highlights The Fact That The Final Rule Is Not The Product Of Reasoned Decisionmaking.....[1206]

7. The Commission's Determination To Adopt The Final Rule In The Absence Of Measurement And Verification Standards Capable Of Preventing Manipulation Is Arbitrary And Capricious .....[1214]

C. The Commission's Conclusion That A Uniform, National Rule For DR Compensation Is Necessary To Ensure That ISO/RTO Rates Are Just And Reasonable Is Arbitrary And Capricious, And Unsupported By Substantial Evidence.....[1220]

1. The Commission Improperly Shifted The Burden Of Proof.....[1220]

2. The Commission's Determination Departs Without Adequate Explanation From Long-Standing Policy Permitting Regional Variations In Market Rules .....[1221]

3. The Commission's Determination To Impose A "One Size Fits All" Rule Is Arbitrary And Capricious .....[1224]

D. The Commission's Rejection Of The LMP-G Alternative Is Arbitrary And Capricious And Not Supported By Substantial Evidence .....[1227]

E. The Commission's Determination Was Contrary To Law And Arbitrary And Capricious Because It Violated The Requirements Of The RFA.....[1232]

IV. CONCLUSION .....[1234]

UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. RM10-17-001

DEMAND RESPONSE COMPENSATION IN ORGANIZED
WHOLESALE ENERGY MARKETS

Apr. 14, 2011

REQUEST FOR REHEARING OF THE COMPETITIVE POWER SUPPLIER ASSOCIATIONS

Pursuant to Section 313(a) of the Federal Power Act (the "FPA"),[1] and Rule 713 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission (the "Commission"),[2] the Electric Power Supply Association ("EPSA"),[3] the Independent Pow-

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[1] 16 U.S.C. § 825*l*(a) (2006).

[2] 18 C.F.R. § 385.713 (2010).

[3] EPSA is the national trade association representing competitive power suppliers, including generators and marketers. Competitive suppliers, which, collectively, account for 40 percent of the installed generating capacity in the United States, provide reliable and competitively priced electricity from environmentally responsible facilities. EPSA seeks to bring the benefits of competition to all power customers. The comments contained in this filing represent the position of EPSA as an organization, but not necessarily the views of any particular member with respect to any issue.

er Producers of New York, Inc. ("IPPNY),"[4] the Electric Power Generation Association ("EPGA")[5] and the New England Power Generators Association, Inc. ("NEPGA")[6] (collectively, the "Competitive Supplier Associations") respectfully request rehearing of the final rule on demand response ("DR") compensation in

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[4] IPPNY is a not-for-profit trade association representing the independent power industry in New York State. Its members include nearly 100 companies involved in the development and operation of electric generating facilities and the marketing and sale of electric power in New York. The comments contained in this filing represent the position of IPPNY as an organization, but not necessarily the views of any particular member with respect to any issue.

[5] EPGA is a regional trade association of electric generating companies that supply wholesale electric power in Pennsylvania and surrounding states. Collectively, EPGA member companies own and operate more than 145,000 megawatts of electric generating capacity, approximately half of which is located in the mid-Atlantic region. The comments contained in this filing represent the position of EPGA as an organization, but not necessarily the views of any particular member with respect to any issue.

[6] NEPGA is the largest trade association representing competitive electric generating companies in New England. NEPGA's member companies represent approximately 27,000 MW of generating capacity in the region. NEPGA's mission is to promote sound energy policies which will further economic development, jobs, and balanced environmental policy. The comments contained in this filing represent the position of NEPGA as an organization, but not necessarily the views of any particular member with respect to any issue.

organized wholesale energy markets issued on March 15, 2011, in the above-captioned proceeding.[7]

As trade associations dedicated to promoting competition, the Competitive Supplier Associations strongly support participation by diverse resources, including DR resources, in independent system operator ("ISO") and regional transmission organization ("RTO") markets, and appreciate the Commission's desire to remove perceived barriers to DR participation in those markets. The Competitive Supplier Associations cannot, however, support the Final Rule. In what Commissioner Philip D. Moeller accurately describes as a "misguided attempt to encourage greater demand response participation,"[8] the Commission has disregarded the statutory limits on its jurisdiction,[9] its statutory and Constitutional duty to ensure

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[7] *Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, FERC Stats. & Regs. ¶ 31,322 (2011) (the "Final Rule"). The Competitive Supplier Associations also request clarification pursuant to Rule 212 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.212 (2010), with respect to a discrete issue discussed in Part III.B.6(b) hereof.

[8] Final Rule, FERC Stats. & Regs. ¶ 31,322, Dissenting Statement of Commissioner Moeller at 1 ("Moeller Dissent").

[9] Concerns regarding jurisdictional issues are set forth in a separate request for rehearing being filed jointly by EPSA, EPGA and other interested parties. *See* Joint Request For Rehearing of the the Electric Power Supply Association, the American Public Power Association, the Electric Power Generation Association and the National Rural Electric Cooperative Association, Docket No. RM10-17-001 (filed Apr. 14, 2011) ("Joint Rehearing Request").

that wholesale rates are just and reasonable as to jurisdictional public utilities, and the potentially devastating impacts that the Final Rule will have on the competitive markets that the Commission has worked hard to foster.

One of the most troubling aspects of the Final Rule is the Commission's failure to respond meaningfully to a massive record—developed through "nearly 3,800 pages of comments, a subsequent technical conference" and post-technical conference submissions[10]—or at least to the largest part of that record, which flatly contradicts the Commission's position that DR resources should be paid the full locational marginal price ("LMP"). The Commission appears to have concluded this rulemaking with the same dubious "presumption" that paying DR resources full LMP is the "correct result" with which it "started."[11] In adopting such a presumption, the Commission has violated the statutory constraints on its authority and unlawfully shifted the burden to the Competitive Supplier Associations and others opposed to that result. Moreover, the Final Rule gives no indication that these parties were even given the promised opportunity to "rebut[]" this unlawful presumption.[12] Such an ap-

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[10] Final Rule, FERC Stats. & Regs. ¶ 31,322 at P 1.

[11] *Demand Response Compensation in Organized Wholesale Energy Markets*, Transcript at 7:20-25, Docket No. RM10-17-000 (Sept. 13, 2010) (Chairman Wellinghoff) ("Tech. Conf. Tr.").

[12] *Id.* at 8:2 (Chairman Wellinghoff).

proach cannot be reconciled with the most basic requirements applicable to agency decisionmaking.

For these and other reasons set forth herein, the Commission should grant rehearing of the Final Rule.

I. STATEMENT OF ISSUES AND ERRORS

In accordance with Rule 713(c) of the Commission's Rules of Practice and Procedure,[13] the Competitive Supplier Associations hereby list each error and each issue on which they seek rehearing of the Final Rule and provide representative precedent in support of their positions on these issues:

1. As discussed in a separate request for rehearing that EPSA and EPGA are filing jointly with the American Public Power Association ("APPA") and the National Rural Electric Cooperative Association ("NRECA"), the Final Rule is contrary to law, because the Commission has greatly exceeded the limits on its jurisdiction under the FPA in attempting to regulate DR compensation. *See* Joint Rehearing Request.

2. The Final Rule is contrary to law, because it will mandate unduly preferential treatment of DR resources and unduly discriminatory treatment of generation resources. *See, e.g.*, 16 U.S.C. §§ 824d, 824e (2006); *Elec. Consumers Res. Council v. FERC*, 747 F.2d 1511, 1515-16 (D.C. Cir. 1984) ("*ELCON*").

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[13] 18 C.F.R. § 385.713(c) (2010).

3. The Final Rule is arbitrary and capricious and contrary to law, because the Commission has provided unduly preferential subsidies to a favored industry group, namely, DR providers, at the expense of generators and other market participants. *See, e.g., Woods Petroleum Corp. v. Dept. of Interior*, 18 F.3d 854, 859-60 (10th Cir. 1994) ("*Woods Petroleum*").

4. The Final Rule is arbitrary and capricious, and is not the product of reasoned decisionmaking, because the Commission failed to address the serious and legitimate objections raised by the Competitive Supplier Associations and other commenters that payment of full LMP would require unduly preferential treatment of DR and unduly discriminate against generators. *See, e.g., Canadian Ass'n of Petroleum Producers v. FERC*, 254 F.3d 289, 299 (D.C. Cir. 2001) ("*CAPP*").

5. The Final Rule is arbitrary and capricious, and is not the product of reasoned decisionmaking, because the Commission failed to address serious objections to its approach, and significant alternatives proposed (namely, payment of LMP with an offset for avoided retail costs), as recognized and described in the dissenting statement of Commissioner Moeller. *See, e.g., American Gas Ass'n v. FERC*, 593 F.3d 14, 21 (D.C. Cir. 2010) ("*AGA*").

6. The Final Rule is arbitrary and capricious, and is not the product of reasoned decisionmaking, because it is not supported by substantial evidence insofar as it is premised on numerous unsupported, unstated, and/or erroneous factual determinations and policy judgments regarding current market conditions and predictions regarding the effects of the Final Rule. *See, e.g., Columbia Gas Transmission Corp. v. FERC*, 628 F.2d 578, 593 (D.C. Cir. 1979) ("*Columbia Gas*"); *Mo. Pub. Serv. Comm'n v. FERC*, 234 F.3d 36, 41 (D.C. Cir. 2000) ("*MoPSC I*").

7. The Final Rule is arbitrary and capricious, and is not the product of reasoned decisionmaking, because the Commission has failed to establish that the "problem" it purports to solve—allegedly inadequate DR participation—in fact exists, or that its proposed solution of increasing DR compensation is reasonably designed to solve that problem. *See, e.g., National Fuel Gas Supply Corp. v. FERC*, 468 F.3d 831, 843 (D.C. Cir. 2006) ("*National Fuel Gas Supply*"); *Mo. Pub. Serv. Comm'n v. FERC*, 337 F.3d 1066, 1076 (D.C. Cir. 2003) ("*MoPSC II*").

8. The Commission's determination that DR must be paid full LMP is arbitrary and capricious, and not the product of reasoned decisionmaking, because the Commission has failed to articulate any legitimate basis for its decision and

has not drawn a "rational connection between the facts found and the choices made." *See, e.g., Motor Vehicle Mfrs. Ass'n of the U.S. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) ("*State Farm*") (internal citations omitted); *MoPSC II*, 337 F.3d at 1076.

9. The Final Rule is contrary to law because it requires each ISO and RTO to change its existing, Commission-approved tariff provisions governing DR compensation without satisfying the requirements of FPA Section 206; namely, by establishing that the existing tariff provisions are unjust and unreasonable and that its proposed replacement is just and reasonable. *See, e.g.*, 16 U.S.C. § 824e (2006); *Atlantic City Elec. Co. v. FERC*, 295 F.3d 1, 8 (D.C. Cir. 2002) ("*Atlantic City*").

10. The Final Rule is contrary to law, because the Commission has no authority under Section 205 of the FPA to impose unilateral changes in rates and has not met, or even made any apparent effort to meet, the requirements of Section 206 of the FPA. *See, e.g.*, 16 U.S.C. § 824d, 824e (2006).

11. The Final Rule is arbitrary and capricious, and is not the product of reasoned decisionmaking, because it will create inefficiencies that will distort production, consumption, and investment incentives, harm competitive markets, impose long-run costs on consumers exceeding

its short-run benefits, and ultimately, threaten long-term reliability. Moreover, the Commission has not responded meaningfully to these serious objections to its proposed approach. *See, e.g., PPL Wallingford Energy LLC v. FERC*, 419 F.3d 1194, 1198-1200 (D.C. Cir. 2005) ("*PPL Wallingford*").

12. The Final Rule is arbitrary and capricious and contrary to law because the Commission equates "just and reasonable" rates with lower prices, and, by focusing solely on lowering jurisdictional rates, without regard to whether the resulting rates are compensatory or confiscatory, the Commission has abdicated its duties under the FPA and the U.S. Constitution to ensure that regulated sellers receive just and reasonable compensation. *See, e.g.*, U.S. Constitution amend. V, cl. 3; 16 U.S.C. §§ 824d, 824e (2006); *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 603 ("*Hope*").

13. The Final Rule is arbitrary and capricious, and is not the product of reasoned decisionmaking, because it is an unexplained departure from Commission precedent on which market participants have placed substantial reliance that previously found and determined that subsidies are not necessary to incentivize DR participation. *See e.g., FCC v. Fox Television Stations, Inc.*, 129 S. Ct. 1800, 1811 (2009) ("*Fox*"); *Greater Boston Television Corp. v. FCC*, 444

F.2d 841, 852 (D.C. Cir. 1970) ("*Greater Boston*"); *PJM Industrial Customer Coalition v. PJM Interconnection, L.L.C.*, 121 FERC ¶ 61,315 (2007) ("*PJM ICC*").

14. To the extent the Commission concluded that existing ISO/RTO mitigation measures are inadequate and must be supplemented by the Final Rule, this finding is contrary to law, because it requires ISOs/RTOs to change existing tariff provisions without satisfying the requirements of FPA Section 206. *See, e.g.*, 16 U.S.C. § 824e (2006); *Atlantic City*, 295 F.3d at 8.

15. To the extent the Commission concluded that existing ISO/RTO mitigation measures are inadequate and must be supplemented by the Final Rule, its determination is arbitrary and capricious, and is not the product of reasoned decisionmaking, because it is not supported by substantial evidence and is an unexplained departure from precedent on which market participants have substantially relied that found that existing ISO/RTO mitigation to be adequate without reference to the level of DR compensation or participation. *See, e.g., Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, FERC Stats. & Regs. ¶ 31,252, *clarified*, 121 FERC ¶ 61,260 (2007), *order on reh'g*, Order No. 697-A, FERC

Stats. & Regs. ¶ 31,268 ("Order No. 697-A"), *clarified*, 124 FERC ¶ 61,055, *order on reh'g*, Order No. 697-B, FERC Stats. & Regs. ¶ 31,285 (2008), *order on reh'g*, Order No. 697-C, FERC Stats. & Regs. ¶ 31,291 (2009), *order on reh'g*, Order No. 697-D, 130 FERC ¶ 61,206 (2010); *Ill. Commerce Comm'n v. FERC*, 576 F.3d 470, 477 (7th Cir. 2009) ("*ICC*"); *Williams Gas Processing Gulf Coast Co. v. FERC*, 475 F.3d 319 (D.C. Cir. 2006) ("*Williams*").

16. The Final Rule is arbitrary and capricious, and is not the product of reasoned decisionmaking, because the Final Rule will result in over-mitigation, which the Commission has found to be just as harmful to competitive markets as under-mitigation, and because the net benefits test would facilitate, or even mandate, the exercise of buyer market power. Moreover, the Commission has not addressed arguments raising these serious objections to its proposed approach. *See, e.g., Wisconsin Pub. Power, Inc. v. FERC*, 493 F.3d 239, 262 (D.C. Cir. 2007) ("*Wisconsin Public Power*"); *Moraine Pipeline Co. v. FERC*, 906 F.2d 5, 9 (D.C. Cir. 1990) ("*Moraine Pipeline*"); *PPL Wallingford*, 419 F.3d at 1198-1200.

17. The Final Rule is arbitrary and capricious, is not the product of reasoned decisionmaking, and lacks a rational basis, because the Com-

mission required ISOs/RTOs to use the net benefits test to determine the hours in which DR would be cost-effective, while at the same time acknowledging that the proposed test is not capable of performing the function for which it was adopted. *See PPL Wallingford*, 419 F.3d at 1198-1200.

18. To the extent the Final Rule would allow costs to be allocated to market participants that are self supplying energy, the Final Rule is arbitrary and capricious, and not the product of reasoned decisionmaking, because it would allocate costs associated with self-supplied energy to parties that do not receive any benefit, even in the short run, from lower LMPs resulting from dispatching DR, and is therefore inconsistent with the stated intent of the cost allocation methodology prescribed in the Final Rule. *See, e.g.*, *State Farm*, 463 U.S. at 43.

19. To the extent that the Final Rule would allow costs to be allocated when market participants are self supplying, the Final Rule is arbitrary and capricious and contrary to law, because it conflicts with the stated purposes of the allocation rule and the very decisions cited in the Final Rule for the proposition that the Final Rule is consistent with long-standing judicial precedent on cost allocation methodology and with the principle of cost causation. *See, e.g.*, *State Farm*, 463 U.S. at 43; *ICC*, 576 F.3d at

477; *KN Energy, Inc. v. FERC*, 968 F.2d 1295, 1300 (D.C. Cir. 1992) ("*KN Energy*").

20. The Final Rule is arbitrary and capricious, and is not the product of reasoned decisionmaking, because the payment of LMP to DR invites fraud and abuse, the evidence in the record, and the Commission's previous determinations demonstrate that current measurement and verification standards and ISO/RTO rules are not sufficient to prevent manipulation or accurately determine whether and how much of an observed demand reduction is made in response to price signals. *See, e.g.*, *MoPSC II*, 337 F.3d at 1076.

21. The Final Rule is contrary to law because the Commission has attempted to shift to commenters opposing the Commission's proposal the Commission's own burden under FPA Section 206 of demonstrating that the existing, Commission-approved ISO/RTO tariff provisions are unjust and unreasonable and that its proposed replacement is just and reasonable. *See, e.g.*, 16 U.S.C. § 824e (2006); *Ala. Power Co. v. FERC*, 993 F.2d 1557, 1571 (D.C. Cir. 1993) ("*Alabama Power*").

22. The Final Rule is arbitrary and capricious, and is not the product of reasoned decisionmaking, because the Commission's decision to adopt a uniform, national rule for DR compensation represents an unexplained and unjustified de-

parture from precedent on which market participants have substantially relied. *See, e.g.*, *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶ 31,281 (2008) ("Order No. 719"), *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292 ("Order No. 719-A"), *order on reh'g*, Order No. 719-B, 129 FERC ¶ 61,252 (2009); *Wis. Valley Improvement v. FERC*, 236 F.3d 738, 748 (D.C. Cir. 2001) ("*Wisconsin Valley*").

23. The Commission's determination to adopt a uniform national rule for DR compensation is arbitrary and capricious, and not the product of reasoned decisionmaking, because it failed to explain how regional differences in ISO/RTO compensation constitute a barrier to entry by DR or how such variations render existing, Commission-approved ISO/RTO DR compensation rules unjust and unreasonable. *See, e.g.*, *State Farm*, 463 U.S. at 43; *CAPP*, 254 F.3d 289, 299.

24. The Final Rule is arbitrary and capricious, and is not the product of reasoned decisionmaking, because the Commission failed to consider alternative DR compensation rules (such as LMP-G) that would avoid the serious legal problems raised by the Commission's proposed approach and are supported by a substantial number (if not a majority) of commenters, in-

cluding all ISOs/RTOs, and by Commission Moeller in his dissenting statement, and that would have avoided the adverse effects of paying DR full LMP *See*, e.g., *AGA*, 593 F.3d at 21; *Laclede Gas Co. v. FERC*, 873 F.2d 1494, 1498 (D.C. Cir. 1989) ("*Laclede Gas*").

25. The Final Rule is contrary to law and arbitrary and capricious, because the Commission failed to comply with the requirements of the Regulatory Flexibility Act of 1980 (the "RFA") to conduct a reasoned analysis of the impact of the Final Rule based on its erroneous conclusion that the Final Rule would affect only ISOs/RTOs, but not small entities, was erroneous. 5 U.S.C. §§ 601-612 (2006); *Thompson v. Clark*, 741 F.2d 401, 405 (D.C. Cir. 1984) ("*Thompson*").

II. BACKGROUND

A. The NOPR.

On March 18, 2010, the Commission issued a notice of proposed rulemaking (the "NOPR")[14] in which it proposed to require ISOs/RTOs to pay DR[15] resourc-

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[14] *Demand Response Compensation in Organized Wholesale Energy Markets*, Notice of Proposed Rulemaking, FERC Stats. & Regs. ¶ 32,656 (2010) (the "NOPR").

[15] The Commission's regulations define DR as "a reduction in the consumption of electric energy by customers from their expected consumption in response to an increase in the price of electric

es[16] participating in ISO/RTO-administered wholesale energy markets the LMP in all hours for demand reductions made in response to price signals. According to the Commission, the proposed changes were necessary "[t]o help ensure that wholesale prices in ISOs and RTOs remain just and reasonable,"[17] because, in the Commission's view, existing DR programs had resulted in "inadequate demand response participation,"[18] which "may be the result of compensation that is no longer just and reasonable."[19] The NOPR went on to suggest that increasing DR compensation and participation is necessary for the Commission to "fulfill its mandate to ensure that rates charged for energy are just and reasonable,"[20] because DR "can lower prices" and "mitigate generator market power."[21] The Commission claimed juris-

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energy or to incentive payments designed to induce lower consumption of electric energy." 18 C.F.R. § 35.28(b)(4) (2010).

[16] A DR resource is "a resource capable of providing demand response." 18 C.F.R. § 35.28(b)(5) (2010).

[17] NOPR, FERC Stats. & Regs. ¶ 32,656 at P 13.

[18] *Id.* at P 10.

[19] *Id.* The Commission added that "that the existing and varying levels of compensation generally fail to reflect the marginal value of demand response resources to ISO and RTO energy markets." *Id.* *See also id.* at P 13 ("[t]he current wholesale compensation levels may therefore be leading to under-investment in demand response resources, resulting in higher, and unjust and unreasonable, prices in the organized electricity markets.").

[20] *Id.* at P 5.

[21] *Id.* at P 4.

diction to regulate DR compensation pursuant to Section 205 of the FPA[22] and the statement of congressional policy in Section 1252(f) of EPAct 2005.[23]

B. The Final Rule.

In the Final Rule, the Commission adopted the NOPR's proposal to pay the full LMP to DR resources participating in ISO/RTO-administered wholesale energy markets, subject to two additional conditions not included in the NOPR, namely, that (1) the DR resource "has the capability to balance supply and demand as an alternative to a generation resource;"[24] and (2) "dispatch of that [DR] resource is cost-effective as determined by the net benefits test."[25] The Com-

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[22] *See id.* at P 5 (*citing* 16 U.S.C. § 824d (2006)).

[23] *See* NOPR, FERC Stats. & Regs. ¶ 32,656 at P 5 (*citing* Pub. L. No. 109-58, § 1252(f), 119 Stat. 594, 965 (2005)).

[24] Final Rule, FERC Stats. & Regs. ¶ 31,322 at P 2.

[25] *Id.* at P 2. According to the Commission, this "cost-effectiveness condition," or "net benefits test," is necessary to account for the fact that "dispatching demand response resources may result in an increased cost per unit ($/MWh) to the remaining wholesale load associated with the decreased amount of load paying the bill," where "customers are billed for energy based on the units, MWh, of electricity consumed." *Id.* at P 3. To address this "billing rate effect," the Commission required the use of the "net benefits test," which is intended "to ensure that the overall benefit of the reduced LMP that results from dispatching demand response resources exceeds the cost of dispatching and paying LMP to those resources." *Id.* In addition, the Final Rule also "sets forth a method for allocating the costs of demand response payments

mission claimed that the Final Rule "is necessary to ensure that rates are just and reasonable in the organized wholesale energy markets,"[26] and declared that "payment by an RTO or ISO of compensation other than the LMP is unjust and unreasonable."[27] According to the Final Rule, paying full LMP is necessary to address various barriers to entry by DR providers[28]—barriers that are acknowledged to exist either at the retail level or that are a result of the disconnect between wholesale and retail rates (and are therefore beyond the Commission's jurisdiction).[29] The Final Rule directed all ISOs/RTOs to file the tariff revisions needed to implement the Final Rule's DR compensation approach, including the net benefits test and the cost allocation mechanism, by July 22, 2011.[30]

The Commission largely dismissed—and, in many cases, simply ignored—comments opposing the approach proposed in the NOPR, insisting that "'issues

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among all customers who benefit from the lower LMP resulting from the demand response." *Id.* at P 5.

[26] *Id.* at P 2.

[27] *Id.* at P 47.

[28] *Id.* at P 58.

[29] *See id.* at P 57.

[30] *Id.* at P 6. In addition, the Commission directed each ISO/RTO to conduct a study of the feasibility of "implementing a dynamic approach which incorporates the billing unit effect in the dispatch algorithm" for the day-ahead and real-time energy markets, and to submit the results of this study to the Commission by September 21, 2012. *Id.* at P 7.

of rate design are fairly technical and, insofar as they are not technical, involve policy judgments that lie at the core of the regulatory mission'"[31] and that, "in making such judgments, the Commission is not limited to textbook economic analysis."[32] In a cursory response to challenges to its jurisdiction to set rates for DR compensation, the Commission stated that Section 205 of the FPA gives it the responsibility to "ensur[e] that all rates and charges for or 'in connection with'" Commission-jurisdictional transmission service or wholesale electric energy" are just and reasonable,[33] and asserted that it has jurisdiction over DR compensation in ISO/RTO-administered markets "because it directly affects wholesale rates."[34] The Commission also invoked the statement of congressional policy in EPAct Section 1252(f) as supporting its claim of jurisdiction to set rates for DR compensation.[35]

C. Commissioner Moeller's Dissent

In a strongly worded and carefully considered dissent, Commissioner Moeller spotlighted many of

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[31] *Id.* at P 46 (internal citations omitted).

[32] *Id.* (internal citations omitted).

[33] *Id.* at P 112 (*citing*16 U.S.C. § 824d (2006)).

[34] Final Rule, FERC Stats. & Regs. ¶ 31,322 at P 112 (*citing* Order No. 719-A, FERC Stats. & Regs. ¶ 31,292 at P 47).

[35] Final Rule, FERC Stats. & Regs. ¶ 31,322 at P 113. In addition, the Commission emphasized that the Final Rule "is not intended to usurp state authority or impede states from taking any actions within their authority." *Id.* at P 115.

the problems with the Final Rule. Commissioner Moeller correctly recognized that the Final Rule is:

> a misguided attempt to encourage greater demand response participation [that] imposes a standardized and preferential compensation scheme that conflicts both with the Commission's efforts to promote competitive markets and with its statutory mandate to ensure supplies of electric energy at just, reasonable, and not unduly discriminatory or preferential rates.[36]

Commissioner Moeller noted the "troubling" way in which the Final Rule appears to be "equating the concept of a just and reasonable rate with a lower price."[37] He also took the majority to task for implying "that the current approach is no longer adequate to ensure that rates remain just and reasonable,"[38] without finding that "the existing region-by-region approach to compensation is unjust and unreasonable."[39]

In addition, Commissioner Moeller observed that the Final Rule "never clearly explains how the existence of barriers, in turn, justifies a payment of full LMP" to DR resources.[40] He emphasized that gen-

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[36] Moeller Dissent at 1.

[37] *Id.* at 7.

[38] *Id.* at 2.

[39] *Id.*

[40] *Id.* Commissioner Moeller observed that "the lack of dynamic prices at the retail level is the ***primary*** barrier" to DR participation and that the Final Rule "does not remedy this barrier and custom-

eration and DR "are not perfect equivalents" and that the two differ "both in terms of physics and in economic impact."[41] According to Commissioner Moeller, the payment of full LMP to DR actually "overcompensat[es]" DR, which receives LMP plus the avoided cost of retail purchases (or "G"), a result that is "economically inefficient, preferential to demand resources, and unduly discriminatory towards other market resources."[42] He further noted that the "net benefits" test, which was opposed by "[a] clear majority of the witnesses (representing a spectrum of interests that included demand response advocates, economists, generators, and the RTOs and ISOs),"[43] adds additional, unnecessary complexity that could have been readily avoided under alternative compensation schemes such as LMP-G.[44]

Commissioner Moeller elaborated on his concerns at the Commission's March 17, 2011 open meeting. There, Commissioner Moeller expressed particular concern that the Commission had ignored the uniform

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ers who pay fixed retail rates will not benefit from lower wholesale market prices." *Id.* at 10 (emphasis added).

[41] *Id.* at 3.

[42] *Id.* at 4.

[43] *Id.* at 6.

[44] *Id.* at 7. Commissioner Moeller added that, while he opposed standardization of DR compensation, if he "were to now support any standardization of demand response compensation, it would be the LMP-G approach, which in my opinion, is the only economically efficient outcome for the markets." *Id.* at 11.

opposition of ISOs/RTOs—"the people who don't have the vested interest" in being paid, or paying, more or less and "who regulate our organized markets"[45]—to two central elements of the Final Rule. He remarked that what all of the ISOs and RTOs asked was "number one don't standardize this across the United States, and yet that's what the rule does. Secondly, they said **please, please, please** don't give us a net benefits test, because we don't know how to do it. Yet that's what the rule did."[46]

"[U]nencumbered by 'textbook economic analysis of the markets subject to [the Commission's] jurisdiction,'"[47] the Final Rule adopted an approach that will, in Commissioner Moeller's view, "result in customers experiencing a short-term benefit by way of a lower LMP, but will also impose long-term costs on the energy markets."[48] He added that "the corrosive effect of overcompensating demand resources over time will come at the expense of other resources, particularly generation resources that will have less to invest in maintaining existing facilities and financing new facilities."[49]

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[45] March 17, 2011 Commission Meeting Tr. at 13:4-6.

[46] *Id.* at 13:8-12 (emphasis added).

[47] Moeller Dissent at 9 (*citing* Final Rule, FERC Stats. & Regs. ¶ 31,322 at P 46).

[48] Moeller Dissent at 9-10.

[49] *Id.* at 10. In his statement at the March 17, 2011 open Commission meeting, Commissioner Moeller added that his concern with the Final Rule is that, if DR is over- compensated, "especially

As discussed below, the Competitive Supplier Associations share Commissioner Moeller's concerns.

III. REQUEST FOR REHEARING

As discussed in a separate request for rehearing that EPSA and EPGA are filing jointly with APPA and NRECA, the Commission must grant rehearing of the Final Rule, because the Commission has overstepped its jurisdiction under the FPA in attempting to regulate DR compensation.[50] Even assuming *arguendo* that the Commission possesses such jurisdiction (and it does not), the Final Rule must be reversed, because it is contrary to law, unsupported by substantial evidence, and not the product of reasoned decisionmaking. Among other things as discussed below, the Final Rule embraced a blatantly preferential approach to ratemaking and subordinated the indisputable rights of jurisdictional public utilities to just and reasonable compensation for jurisdictional services to some imagined right on the part of non-jurisdictional entities to compensation for non-jurisdictional services. The Commission has also utterly failed to respond meaningfully to any number of substantial objections raised in response to the NOPR.

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at a time when we are coming out of an economic downturn, we could have job-killing results, and that's not what I, I don't think anyone wants." March 17, 2011 Commission Meeting Tr. at 12:8-11.

[50] *See* Joint Rehearing Request.

A. The Final Rule Is Contrary To Law And Arbitrary And Capricious, Because It Mandates Unduly Preferential Treatment Of DR Resources And Undue Discrimination Against Generators.

As Commissioner Moeller correctly stated, the Final Rule, by requiring ISOs/RTOs to pay DR full LMP, "results in overcompensation that is economically inefficient, preferential to demand resources, and unduly discriminatory towards other market resources."[51] DR resources and generation are not "equivalent," or similarly situated, in terms of their physical characteristics, economics, performance requirements and penalties, and the value of the service provided by DR resources is indisputably inferior to that provided by dispatchable generation for operational and reliability purposes.[52] In light of these significant differences, it was unduly preferential and unduly discriminatory for the Commission to require DR resources and generators to receive the same com-

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[51] Moeller Dissent at 4.

[52] As PJM Power Providers Group ("P3") explains in its comments, DR resources cannot "be relied upon for reliability, planning and operational security purposes by the RTO on an equivalent basis to dispatchable generation" because, unlike generation, DR providers "are not forced to reduce their load during peak periods or at any other times." Comments of the PJM Power Providers Group at 2-3, Docket No. RM10-17-000 (filed May 12, 2010) ("P3 Comments").

pensation.[53] The Final Rule, however, went even further by requiring DR providers to be ***paid more*** for providing a ***lower quality***, non-jurisdictional service than generators receive for jurisdictional sales.[54] And to add insult—or, to be more precise, additional injury —to injury, the Final Rule again discriminated against generators by requiring them to foot the bill (through suppressed energy prices and in other ways[55]) for the

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[53] *See, e.g., Ala. Elec. Coop., Inc. v. FERC*, 684 F.2d 20, 254 (D.C. Cir. 1982) (explaining that charging the same rate to customers that are not similarly situated "may be considered discrimination," just as charging "different rates to customer classes which are similarly situated" may be unduly discriminatory).

[54] *See ELCON*, 747 F.2d at 1515-16 (finding rate design to be unduly discriminatory where the Commission and the filing utility failed to provide evidence justifying differences in rates to otherwise similarly situated customers that resulted in high-load factor customers subsidizing low-load factor customers).

[55] In addition to the suppression of LMPs, generators may also be forced to subsidize DR to the extent they are net energy buyers in the real-time energy market. For example, there is no assurance that a fast start resource whose offer clears in the day-ahead energy market will actually be dispatched in the real-time energy market. Under existing ISO/RTO market rules, this typically means that the fast start resource pays no more than its energy offer price for any shortfall. Under the Final Rule, however, it appears that this resource could also be allocated uplift costs that would cause the owner of the fast start resource to pay more than its own self-supply cost, despite being economic.

subsidy that the Commission has required ISOs/RTOs to pay to DR resources.[56]

1. DR Resources And Generation Are Not "Equivalent," Nor Do They Have The Same Marginal Value.

The Commission's determination that DR resources and generation are equivalent or have the same marginal value[57] is both factually incorrect and logically inconsistent. There are significant differences between DR resources and generation in terms of their physical characteristics, economic value, and the services they provide.[58] As ISO New England Inc. ("ISO-NE") observed, the Commission's proposal

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[56] *See, e.g.*, Comments of the Edison Electric Institute at 22-23, Docket No. RM10- 17-000 (filed May 13, 2010) ("EEI Comments") (arguing that the subsidy inherent in the Final Rule "constitutes undue discrimination" because the suppression of LMPs caused by the subsidy will "merely benefit Buyers at the expense of Sellers [and] are not an economic benefit").

[57] Final Rule, FERC Stats. & Regs. ¶ 31,322 at PP 47, 67.

[58] A substantial amount of DR is provided by "backup" or "behind-the-meter" generators, most of which are diesel units that lack emissions controls and that have a heat rate substantially higher than the system average. Such generator-based DR resources reduce the amount of demand that must be met through ISO/RTO-administered energy markets, but they do not reduce the customer's overall consumption; instead, they simply shift demand off the ISO/RTO system. *See* Comments of the Electric Power Supply Association, Docket No. RM10-17-000 (filed May 13, 2010) ("EPSA Comments"), Attachment 1, William W. Hogan, Implications for Consumers of the NOPR's Proposal to Pay the LMP for all Demand Response at 8-9 ("Hogan Policy Paper").

in the NOPR was apparently "based on the false assumption that demand resources and generators are equivalent,"[59] and it ignored the fact that non-generator based DR resources "are physically different from generators—demand resources reduce consumption whereas generators serve consumption."[60] In fact, non-generator based DR "is not a 'resource' like generation, in that it cannot actually power residences, commercial establishments or industrial facilities."[61]

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[59] Comments of ISO New England Inc. at 3, Docket No. RM10-17-000 (filed May 13, 2010) ("ISO-NE Comments").

[60] *Id.*; *see also id.* at 35 ("[i]n contrast to generation resources that physically inject energy into the wholesale power grid, demand resources physically reduce the withdrawal of energy from the wholesale power grid.").

[61] Comments of the American Public Power Association and the National Rural Electric Cooperative Association at 12, Docket No. RM10-17-000 (filed May 13, 2010) ("APPA/NRECA Comments"). Generator-based DR resources are "resources" capable of serving retail load. While these resources are physically similar to other generators (apart from the fact that they are, on average, less efficient and more polluting), they are not similarly situated in terms of economics, compensation, or treatment under ISO/RTO rules. In particular, a customer with behind-the-meter distributed generation ("DG") units can use the DG unit's output ***both*** to serve its own (unreduced) load ***and***, at the same time, sell the output as price-responsive DR. By contrast, a generator located on the ISO/RTO side of the meter would have to either sell the output as generation ***or*** use the generation to serve the customer's load, and receive correspondingly lower compensation. Hogan Policy Paper at 7-9.

The economics and financial incentives of generators and DR resources are also fundamentally different. As the Illinois Commerce Commission (the "ICC") correctly observed: "In pure economic terms a reduction in demand is fundamentally different from an increase in supply. Demand reductions and supply increases are ***not only*** intuitively divergent, but treating them equivalently has material implications."[62] NEPGA described the economic differences between the two as follows:

> There is no need to deduct costs from the LMP payments made to generators, because generators actually incur those costs to deliver power. When they receive LMP, they earn the net amount equal to LMP minus their costs. Demand response providers, in contrast, would be paid, under the NOPR, to not do something—to not consume power. And in the normal course, the reward for not buying something is avoiding paying for what you do not buy.[63]

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[62] Comments of the Illinois Commerce Commission at 2, Docket No. RM10-17-000 (filed May 13, 2010) ("ICC Comments") (emphasis in the original).

[63] Comments of the New England Power Generators Association, Inc. at 4-5, Docket No. RM10-17-000 (filed May 13, 2010) ("NEPGA Comments"). *See also* ISO-NE Comments at 19 ("[t]he primary motivation of a wholesale generator is to earn revenue in excess of costs, while the primary motivation of a participant with a demand resource is to reduce its net energy bill.").

If generation and DR resources in fact had the same marginal value, then LSEs and ISOs/RTOs would be indifferent between dispatching a DR resource and generation. This is not the case, however, because ISOs/RTOs incur a net loss when paying DR LMP, whereas they break even when paying generators LMP.[64] Moreover, the fact that the Commission felt compelled to bolt a net benefits test and a cost allocation mechanism on to its initial proposal is further evidence, if any were needed, that a one MW reduction in demand is not economically equivalent to a one MW increase in supply.[65] This disparate treatment is neither comparable nor efficient, because it values a

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[64] *See* Comments of the New York Independent System Operator, Inc. at 10, Docket No. RM10-17-000 (filed May 13, 2010) ("NYISO Comments").

[65] The Commission explained that the net benefits test is needed in cases where "the next unit of generation is not sufficiently more expensive than the demand response resource" because:

> In this situation, dispatching the demand response resource would result in a higher price to remaining customers than the dispatch of the next unit of generation in the bid stack. While the demand response resource appears cost competitive in the dispatch order, selection of the demand response resource increases the total cost per unit to remaining load, and it would not be cost-effective to dispatch the demand response resource.

Final Rule, FERC Stats. & Regs. ¶ 31,322 at P 52. Thus, a one MW increase in supply will frequently be more cost-effective than a one MW decrease in demand. In these situations, DR and generation are ***not*** economically equivalent.

"negawatt" more than a megawatt and will harm efficiency and competition in organized markets.[66]

The operational and reliability benefits of DR are also fundamentally different from those provided by generation under current ISO/RTO market rules, because DR resources are not obligated to reduce their load during peak periods or, indeed, at any other times, which means that DR resources cannot be relied upon for reliability, planning, and operational security purposes by the ISO/RTO in the same way as generation resources.[67] Unlike generation, DR resources may be called on only a limited number of times per year for reliability purposes, whereas generators must be available for dispatch every day of the year,[68] and DR resources can provide balancing service only for relatively short periods.[69] Nor is a reduction in consumption comparable to an increase in production for the purposes of balancing supply and demand "when neither the DR provider, nor the LSE with the obligation to serve the load behind the [DR resource] has a day-ahead position."[70] Moreover, the Final Rule ig-

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[66] Moeller Dissent at 5.

[67] *See* P 3 Comments at 2-3.

[68] Comments of the PSEG Companies at 8, Docket No. RM10-17-000 (filed May 13, 2010).

[69] Comments of American Electric Power Service Corporation at 7-8, Docket No. RM10-17-000 (filed May 13, 2010).

[70] Comments of the Midwest Independent Transmission System Operator, Inc. at 10-11, Docket No. RM10-17-000 (filed May 13, 2010) ("Midwest ISO Comments"). The Midwest Independent

nored the fact that the marginal value of DR is likely to **decrease** as its participation levels increase and DR becomes a progressively worse substitute for generation as it approaches the "saturation" point.[71]

In addition, the Commission's determination is arbitrary and capricious, because its rationale for adopting the Final Rule is internally inconsistent. On

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Transmission System Operator, Inc. (the "Midwest ISO") offered the following example to demonstrate the point:

> Suppose we expect load to increase by 20 MW in the next five minute interval and suppose that we dispatch a [DR resource] to meet that load increase. If the load behind the [DR resource] was going to start withdrawing energy over the next five minute interval but had not prior to the dispatch, then deploying the [DR resource] does not ensure meeting the energy balance. The RTO would still have to call on additional generation to meet that load increase.

Id. at 11.

[71] *See* P 3 Comments at 33-34. While the Final Rule does not even acknowledge that there may be an upper limit on the level of DR participation, much less attempt to estimate what the saturation point would be, ISOs/RTOs such as PJM Interconnection, L.L.C. ("PJM") have begun to study the issue as a result of the massive increase in DR participation in recent years. *See, e.g.*, PJM Resource Adequacy Planning Department, Demand Resource Saturation Analysis (dated May 2010), *available at*: http://www.pjm. com/~/media/committees-groups/committees/mrc/20100518/20100518-item-05-dr-saturation-report.ashx. PJM noted that it currently limits DR to 7.5 percent of forecasted unrestricted peak load and that DR participation has dramatically increased in recent years, from 1.2 percent of load in 2006/2007 to 6.3 percent in 2010/2011. *Id.* at P 3. DR participation in PJM is thus already rapidly approaching the current assumed saturation limits.

the one hand, the Commission claimed that DR is different from generation, and, therefore, requires greater compensation to eliminate barriers to entry and other market imperfections (*e.g.*, in rejecting the "LMP-G" alternative).[72] On the other hand, the Commission insisted that DR must be treated the same as generation, erroneously claiming that the Commission does not consider costs in setting rates for participants in ISO/RTO-administered markets "[i]n the absence of market power concerns."[73] Leaving aside the dubious accuracy of the last qualifier,[74] the Commission's reasoning fails, because it rests on the contradictory propositions that DR is both different from, and the same as, generation, with the only unifying "principle" being the conclusion that DR should be paid full LMP

2. DR Resources Are Not Comparable And Are Not Entitled To The "Same" Compensation As Generators, Much Less The Unduly Preferential Compensation Required By The Final Rule.

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[72] Final Rule, FERC Stats. & Regs. ¶ 31,322 at P 61.

[73] *Id.* at P 62 (claiming that, "[i]n the absence of market power concerns, the Commission does not inquire into the costs or benefits of production for the individual resources participating as supply resources in the organized wholesale electricity markets and will not here, . . . single out demand response resources for adjustments to compensation.").

[74] Screens based on generator costs are often applied to determine whether an individual generator is exercising market power, an assessment that will frequently occur when there are no identified market power concerns.

The Commission also failed to establish that DR resources and generation should receive the same compensation,[75] even in the limited range of circumstances where they may be substitutes, *e.g.*, for the provision of balancing services,[76] and certainly not across the full range of the supply and demand curves.[77] As the Edison Electric Institute ("EEI") explains:

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[75] The Final Rule does not, in fact, require the same or "comparable" compensation for DR resources and generation, notwithstanding the Commission's statements to the contrary. Generators receive LMP (minus fuel and other variable costs), whereas DR resources would receive LMP, plus a subsidy equal to the avoided costs of foregone retail purchases.

[76] The Commission asserted that commenters opposing this finding "do not adequately recognize a distinctive and perhaps unique characteristic of the electric industry," which "requires instantaneous balancing of supply and demand at all times to maintain reliability." Final Rule, FERC Stats. & Regs. ¶ 31,322 at P 56. *See also id.* at P 23 (discussing comments including those of American Electric Power Service Corporation ("AEP") and Calpine Corporation ("Calpine")). The Commission's reliance on such a patently false assertion—that sophisticated market participants such as AEP and Calpine are unaware of the unique features of the industry in which they operate—does not pass the laugh test, much less satisfy the Commission's duty to engage in reasoned decisionmaking. *See, e.g., MoPSC II*, 337 F.3d at 1076 ("[r]eliance on facts that an agency knows are false at the time it relies on them is the essence of arbitrary and capricious decisionmaking.").

[77] To the extent that DR is providing a balancing service on a comparable basis, it should be compensated as such (although, as discussed above, a decrease in consumption is not comparable to an increase in supply in the absence of an advance purchase obligation). As EPSA explained in its reply comments, however, balanc-

> Because generators deliver energy to the market and Demand Response Resources do not, their respective products are not fungible, [and] therefore do not have comparable economic values. Furthermore, because demand response is not energy it cannot be traded in the energy market; consequently, the fact that generators are paid LMP in any given hour provides insufficient information regarding what Demand Response Resources should be paid for reducing load in that same hour.[78]

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ing services have wholly different compensation algorithms from generation resources. *See* Reply Comments of the Electric Power Supply Association at 33, Docket No. RM10-17-000 (filed June 30, 2010) ("EPSA Reply Comments"). In most markets, balancing services are compensated relative to opportunity costs. PJM, ISO-NE, the Midwest ISO, and the New York Independent System Operator, Inc. (the "NYISO") all have fully functioning ancillary services markets that buy and sell balancing services to the grid. For examples of how different values are placed on differing products, *see: A Review of Generation Compensation and Cost Elements in the PJM Markets* (2009), *available at:* http://www.pjm.com/~/media/committees-groups/committees/mrc/20100120/20100120-item-02-review-of-generation-costs-and-compensation.ashx. Under these compensation regimes, however, compensation is not a direct reflection of the supply of electricity because DR bids cannot abide by all of the parameters and requirements of supply, as discussed in more detail below.

[78] EEI Comments at 15. *See also* Midwest ISO Comments at 6 ("[b]ecause demand response does not deliver energy, prices in the energy markets are not indicative of the compensation that DR providers should receive for their so-called 'Negawatts.'").

Given the qualitative differences between the quality and types of services provided by DR resources and generation described above,[79] "comparable" compensation does not mean the two must receive the "same" compensation, and it certainly does not justify providing more compensation for the inferior product.[80] Finally, to the extent the Commission relied on Order No. 890[81] in support of the DR compensation approach

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[79] As discussed in Section III.C.3 below, however, each ISO/RTO offers several DR products with differing prices and technical requirements, and the Commission has failed to establish why all of these heterogenous DR products must receive the same compensation, much less why all of these disparate DR products must receive higher compensation than generation.

[80] If rehearing is not granted, the Final Rule will give customers the incentive to move or install generator-based DR resources behind-the-meter so that output can serve customer load (without any reduction in consumption), and the customer can simultaneously sell the same output as price responsive DR. By contrast, if the generator is located on the ISO/RTO side of the meter, it would have to ***either*** sell the output as generation ***or*** use the generation to serve the customer's load, and receive correspondingly lower compensation. Hogan Policy Paper at 7-8. The Final Rule thus not only subsidizes generator-based DR units that are less efficient and more polluting than other generators, but the subsidy ensures that these units will run more frequently when installed behind-the-meter than they would if installed on the ISO/RTO side of the meter because the DG unit will be "cost-effective" whenever its costs are ***less than or equal to LMP plus the retail rate***, whereas the latter generator would be dispatched only when its costs are less than or equal to LMP. *See* Hogan Policy Paper at 9-10.

[81] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241

adopted in the Final Rule, its reliance is misplaced. There, the Commission required transmission providers to provide "comparable" compensation for generation and transmission solutions, but did not require that that the two receive the "same" compensation.[82] And it certainly did not require that inferior solutions receive higher compensation.

The Commission's decision to require ISOs/RTOs to pay non-jurisdictional DR providers more than jurisdictional generators for a demonstrably inferior service raises serious concerns that the Commission's

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("Order No. 890"), *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007) ("Order No. 890-A"), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009) *order on reh'g*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

[82] *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 495 (clarifying that the requirement to give comparable treatment to DR resources and generation does not mean "that each and every transmission customer should be treated the same."). *See also* Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 at P 216 (concluding that treating similarly-situated generation and DR resources "on a comparable basis does not necessarily mean that the resources are treated the same."). Similarly, in acting on the Order No. 719 compliance filings, the Commission has held that "'comparability' is not achieved by setting conditions for demand response resources the same as those set for generating resources." *PJM Interconnection, L.L.C.*, 129 FERC ¶ 61,250 at P 46 (2009). *See also New York Indep. Sys. Operator, Inc.*, 129 FERC ¶ 61,164 at P 67 (2009), *on reh'g*, 131 FERC ¶ 61,174 (2010) (same); *California Indep. Sys. Operator Corp.*, 129 FERC ¶ 61,157 at P 42 (2009), *on reh'g*, 131 FERC ¶ 61,110 (2010) (same).

Final Rule is improperly subsidizing a favored industry group (namely DR providers) at the expense of generators and other customers.[83] Rulemaking on that basis is clearly unlawful, because it not only lacks any justification in the FPA, but in fact contravenes the governing statute, which prohibits granting "any undue preference or advantage to any person" or subjecting "any person to any undue prejudice or disadvantage."[84]

3. The Commission's Decision Is Arbitrary And Capricious, Because It Fails To Address Serious Objections That Its Proposed Approach Is Unduly Preferential And Unduly Discriminatory.

The Final Rule is arbitrary and capricious, because the Commission has failed to offer any meaningful response to the arguments made by commenters and Commission Moeller that the Final Rule is unduly preferential to DR providers and unduly discriminates against generators.[85] In particular, the Commission ignored serious objections that DR resources should receive comparable compensation to generators "only if both are subject to the same market participation rules, penalty structures, testing requirements, and market monitoring provisions,"[86] which they are not.

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[83] *See Woods Petroleum*, 18 F.3d at 859-60.

[84] *See* 16 U.S.C. § 824d(b)(1) (2006).

[85] *See, e.g.*, *CAPP*, 254 F.3d at 299; *AGA*, 593 F.3d at 21.

[86] Final Rule, FERC Stats. & Regs. ¶ 31,322 at P 66.

The Commission's suggestion that ISOs/RTOs "already consider comparability between [DR] and generation in terms of market rules" and will continue to do so in the future would seem to obviate the need for the rule.[87] That is to say, if ISOs/RTOs already treat DR and generation comparably, then why is it necessary to increase DR compensation to ensure comparable treatment?[88]

B. The Commission's Determination That The Final Rule Is Necessary To Make ISO/RTO Rates Just And Reasonable Is Contrary To Law, Arbitrary And Capricious, And Not Supported By Substantial Evidence.

The Commission has failed to explain why and how existing ISO/RTO provisions that provide for differing DR compensation are unjust and unreasonable[89] and why and how payment of LMP will cause rates to be just and reasonable[90] in order to satisfy the requirements of the FPA.[91] As an initial matter, although

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[87] *Id.* at P 67.

[88] In many respects, DR is treated better than generation under existing ISO/RTO market rules, because it generally receives the same or higher compensation for a lower value product with fewer obligations. This is particularly true in capacity markets.

[89] *See* Final Rule, FERC Stats. & Regs. ¶ 31,322 at P 47 ("payment by an RTO or ISO of compensation other than LMP is unjust and unreasonable.").

[90] *See id.* ("payment of LMP to these resources will result in just and reasonable rates for ratepayers.").

[91] 16 U.S.C. § 824e (2006).

the Final Rule does not contain even a single citation to Section 206 of the FPA, one can only assume that this is the claimed source of authority for the Final Rule, because it is the ***only*** provision of the FPA under which the Commission, acting *sua sponte*, could order modifications to ISO/RTO tariffs, such as those contemplated by the Final Rule. If and to the extent that the Commission acted under Section 205 of the FPA,[92] the Final Rule is plainly contrary to law, because, as the courts have repeatedly emphasized, the Commission "has no power to force public utilities to file particular rates unless it first finds the existing filed rates unlawful,"[93] something it can do only under Section 206 of the FPA.[94]

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[92] The Commission implicitly conceded the inapplicability of FPA Section 205 when it stated that the "tariff changes directed herein should be submitted as compliance filings pursuant to this Final Rule, not pursuant to section 205 of the [FPA]." Final Rule, FERC Stats. & Regs. ¶ 31,322 at P 6.

[93] *Atlantic City*, 295 F.3d at 8 (*citing Pub. Serv. Comm'n v. FERC*, 866 F.2d 487, 488-89 (D.C. Cir. 1989)).

[94] In a case discussing Sections 4 and 5 of the Natural Gas Act (the "NGA"), which are analogous to, and which may be "cite[d] interchangeably" with, Sections 205 and 206 of the FPA, *Arkansas La. Gas Co. v. Hall*, 453 U.S. 571, 577 n.7 (1981) ("*Arkla*"), the D.C. Circuit made clear its frustration with past Commission failures to respect the difference between the two means of changing rates, stating:

> This court "has consistently disallowed attempts to blur the line between §§ 4 and 5." *Public Serv. Comm'n v. FERC*, 866 F.2d 487, 491 (D.C. Cir. 1989). As we complained four years ago, "[o]n four

The Final Rule falls well short of satisfying the requirements of Section 206. Blanket assertions that increased DR compensation will lower jurisdictional rates and mitigate market power, even if true, do not satisfy the requirements of Section 206 or provide for the substantial evidence and reasoned decisionmaking necessary to survive judicial review.

Moreover, the Commission must establish a rational connection between the perceived problem (*i.e.*, barriers to DR entry that, according to the Commission, have limited DR participation and may cause jurisdictional rates to become unjust and unreasonable) and its chosen solution of adopting a uniform, national rule requiring increasing wholesale DR compensation.[95] As Commissioner Moeller correctly observed, the Final Rule "never clearly explains how the existence of barriers, in turn, justifies a payment of full LMP to [DR] resources,"[96] nor could it, as there is simply nothing it could say that would justify the Commis-

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occasions in the last three years this court has reviewed Commission efforts to compromise § 5's limits on its power to revise rates. On each the court has repelled the Commission's gambit. This is number five." *Id.* at 488-89. We now make it an even six.

Western Resources, Inc. v. FERC, 9 F.3d 1568, 1578 (D.C. Cir. 1993).

[95] *See, e.g.*, *State Farm*, 463 U.S. at 43 (explaining that an agency action is "arbitrary and capricious" where it fails to "articulate a satisfactory explanation for its action including a 'rational connection between the facts found and the choices made.'") (*quoting Burlington Truck Lines v. U.S.*, 371 U.S. 156, 168 (1962)).

[96] Moeller Dissent at 2.

sion's assertion of ratemaking jurisdiction over DR compensation in the Final Rule. Instead, the Commission appears to have assumed the conclusion that it must prove, insofar as it adopted a "presumption" that payment of full LMP is the "correct result," and thereby shifted to commenters the burden of rebutting that presumption.[97] The Final Rule should therefore be reversed for failing to demonstrate that the "problem" that the rule purports to address actually exists or that the Commission's chosen solution is capable of addressing that problem.[98]

In addition, the Commission dismissed or ignored altogether the objections submitted by a wide spec-

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[97] At the September 13, 2010 Technical Conference, Chairman Wellinghoff described the starting point for the Commission's consideration of comments on the NOPR's proposal:

> I think this is an extremely important meeting we are having here.
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> [T]he ***presumption*** here is that there should be equivalent compensation for equivalent services, and that's where the Commission started here. ***We started with giving the full LMP to Demand Response for bidding into these markets.***
>
> And I still believe that's the correct result. It's a presumption. It's a presumption certainly that is subject to being rebutted. We want to hear today from those people who support that presumption, and those here today who have some evidence and information that might rebut that.

Tech. Conf. Tr. at 7:19-8:5 (emphasis added).

[98] *See, e.g.*, *National Fuel Gas Supply*, 468 F.3d at 843 ("Professing that an order ameliorates a real industry problem but then citing no evidence demonstrating that there is in fact an industry problem is not reasoned decisionmaking.").

trum of commentators (including not only generator interests, but also ISOs/RTOs, market monitors, State commissions, LSEs, and consumer groups) who opposed the Final Rule's mandate to pay DR full LMP, as well as those of Commissioner Moeller, who accurately described the Final Rule as "a misguided attempt to encourage greater demand response participation."[99] By "fail[ing] to acknowledge, much less substantively address,"[100] the serious concerns raised by Commissioner Moeller and commenters, the Commission has failed to fulfill its duty to engage in reasoned decisionmaking.

1. The Final Rule Is Based On Numerous Erroneous And/Or Unsupported Assumptions And Policy Judgments.

The Final Rule rests on a number of erroneous and/or unsupported assumptions and policy judgments, including assumptions and judgments to the effect that (1) current levels of DR participation are inadequate due to inadequate or varying levels of compensation; (2) current levels of DR compensation are inadequate; (3) increasing wholesale DR compensation by subsidizing DR will eliminate or mitigate barriers to entry by DR; and (4) the amount of the required subsidy should be equal to the avoided costs of retail

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[99] Moeller Dissent at 1.

[100] *AGA*, 593 F.3d at 21.

purchases.[101] In addition to relying on these flawed premises, the Final Rule rests on faulty logic and rank speculation to the effect that the Final Rule is the only solution to the "problem" of inadequate DR participation. Consequently, the Final Rule is not supported by substantial evidence and is not the product of reasoned decisionmaking.[102] Compounding the problem is the fact that certain of these critical premises are not expressly set forth in the Final Rule but can only be inferred from the relatively sparse reasoning of the order.[103] This is yet another respect in which the Final Rule is arbitrary and capricious, because the Commission has failed to "articulate the critical facts on which it relie[d]" or to "fully explain the assumptions on it relied on to resolve unknowns and the public policies behind those assumptions."[104]

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[101] In addition, the Final Rule relied on two other assumptions—namely, that DR resources and generation are "equivalent" and that they therefore deserve the "same" compensation—both of which are erroneous, for the reasons discussed in Section III.A.1 and III.A.2, supra.

[102] *See, e.g., MoPSC II*, 337 F.3d at 1072-75 (vacating and remanding Commission orders because it found, among other things, that the Commission had failed to articulate the actual reasons for its decision, and the reasons it did cite were "speculative," unsupported by record evidence, and did not support its decision).

[103] *See infra* n.105.

[104] *Columbia Gas*, 628 F.2d at 593. *See also Connecticut Light & Power Co. v. NRC*, 673 F.2d 525, 530 (D.C. Cir. 1982) (explaining that the Commission must "provide an accurate picture of the reasoning that has led the agency to [a] proposed rule").

First, the Final Rule is predicated on an apparent conclusion that current levels of DR participation are inadequate due to existing, inadequate compensation rules,[105] but there is no evidence to support this conclusion or any Commission finding as to what the appropriate or "optimal" level of DR participation should be. Nor did the Commission "explain how the lack of a uniform compensation approach in each RTO-run market is a barrier to demand response"[106] or how differences in compensation among ISOs/RTOs may have caused DR participation levels to be sub-optimal.[107] Tellingly, in the Final Rule, the Commis-

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[105] In the NOPR, the Commission stated that, after observing DR participation levels in ISOs/RTOs with differing DR structures it was concerned "that some existing, inadequate compensation structures have hindered the development and use of demand response." NOPR, FERC Stats. & Regs. ¶ 32,656 at P 9. While the Commission did not repeat these claims in the Final Rule, the Final Rule "implie[d]" that the Commission continues to believe that "the current approach is no longer adequate to ensure that rates remain just and reasonable," as Commissioner Moeller correctly notes. Moeller Dissent at 2. Had the Commission reached a different conclusion, *i.e.*, that DR participation and compensation are in fact adequate, it would have been compelled to admit that the Final Rule is unnecessary and unjustified.

[106] APPA/NRECA Comments at 4.

[107] Moreover, the Commission reached this conclusion without addressing issues such as what the appropriate maximum limit of DR participation should be (*i.e.*, the "saturation point" or "fatigue point"). *See* Post-Conference Comments of the Electric Power Supply Association at 9, Docket No. RM10-17-000 (filed Oct. 13, 2010). This is a significant issue because, as explained above in Section III.A.1, the marginal value of DR resources decreases as

sion did not rely on the "case study" cited in the NOPR as demonstrating that a decrease in DR compensation caused a decrease in DR participation,[108] presumably because that study expressly rejects the proposition for which it was cited.[109] The Commission also utterly failed to respond to evidence submitted by the Competitive Supplier Associations and others demonstrating that the decreases in DR participation in economic DR programs from 2008 to 2009 were the result of generally lower energy prices, as opposed to deficiencies in the DR compensation mechanisms in place in

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DR penetration approaches the "saturation" point, further undermining the Commission's claim that generation and DR resources have the same marginal value.

[108] *See* NOPR, FERC Stats. & Regs. ¶ 32,656 at P 10 (*discussing* Monitoring Analytics, LLC Barriers to Demand-side Response in PJM (dated July 1, 2009), ("PJM IMM Barriers to Entry Report"), *available at*: http://www.monitoringanalytics.com/reports/Reports/2009.shtml).

[109] Monitoring Analytics, LLC ("Monitoring Analytics"), the Independent Market Monitor ("IMM") for PJM, concluded that: "[t]he evidence does not support the claim that the removal of the incentive program resulted in a reduction of activity in the Economic Program" and that demand-side subsidies do not directly address the root problem—the lack of real time price information at the retail level. PJM IMM Barriers to Entry Report at 22, 27. *See also* Monitoring Analytics, LLC, *2009 State of the Market Report for PJM* at 17 (dated Mar. 11, 2010), *available at*: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2009/2009-som-pjm-volume1.pdf ("[t]here were many factors that contributed to lower levels of participation and lower revenues in the Economic Program, including lower price levels in 2009, lower load levels, and improved measurement and verification.").

these markets.[110] The Commission has thus set a policy goal of increasing DR participation, without making any determination as to what the target level of participation should be. As a result, there is no benchmark that the Commission, ISOs/RTOs, State commissions, or market participants can use to measure progress towards attaining this goal or to determine when the target has been reached, suggestng that the Commission-mandated subsidies for DR would remain in place indefinitely.

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[110] *See* EPSA Comments at 15; APPA/NRECA Comments at 4 ("[w]hile participation in economic demand response programs in several RTO-run markets has declined in 2009, compared to 2008, this reflects the decline in RTO prices during that timeframe, and it is not, in itself, a reason to prescribe a uniform compensation approach based on paying full LMP to demand response resources."). *See also* Federal Energy Regulatory Commission, *State of the Markets Report 2009* at 7 (Apr. 15, 2010) ("Commission 2009 SOM Report"), *available at*: http://www.ferc.gov/market-oversight/st-mkt-ovr/som-rpt-2009.pdf ("[w]ith lower electricity prices and lower fuel costs, electricity prices fell by half" from 2008 to 2009); Monitoring Analytics, LLC, *2010 State of the Market Report for PJM* at 30 (March 10, 2011) ("PJM 2010 SOM Report"), *available at*: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2010/2010-som-pjm-volume1.pdf ("[p]articipation levels through calendar year 2009 and through the first three months of 2010 were generally lower compared to prior years due to a number of factors, including lower price levels, lower load levels, and improved measurement and verification, but have showed strong growth through the summer period as price levels and load levels have increased.").

Second, the Commission has not identified any convincing evidence that current levels of DR compensation are in fact inadequate. Instead, the only supporting evidence, if it can be called evidence, lies in the self-serving statements of various DR providers.[111] In addition, the Commission's reasoning on this point is completely circular, and boils down to a theory that DR compensation must be inadequate because DR participation is inadequate.[112] But the record evi-

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[111] *See, e.g.*, Comments of Viridity Energy, Inc. at 4, Docket No. RM10-17-000 (filed May 13, 2010) ("[t]he near absence of [DR] service from the energy markets is power empirical proof that the current level of compensation is inadequate"); Comments of EnerNOC in Response to Notice of Proposed Rulemaking at 2, Docket No. RM10-17-000 (filed May 13, 2010) ("[c]urrent compensation to demand response in organized wholesale markets is inadequate and undervalues demand response as a resource."); Comments of the Demand Response and Smart Grid Coalition at 5, Docket No. RM10-17-000 (filed May 13, 2010) ("[t]he Commission has rightly concluded that the current compensation provided for demand response resources is inadequate in most of the organized markets and that LMP is the proper payment required to ensure adequate demand response.").

[112] *See, e.g.*, NOPR, FERC Stats. & Regs. ¶ 32,656 at P 13 ("current compensation levels appear to have become unjust and unreasonable.") Again, the Commission did not repeat its claims from the NOPR that DR compensation is inadequate or that it has become unjust and unreasonable, but if it had not concluded that DR compensation is inadequate, it would have had no reason to adopt the Final Rule requiring ISOs/RTOs to increase DR compensation. As such, the Commission acted arbitrarily and capriciously by failing to articulate the critical facts and assumptions on which it relied. *See, e.g.*, *Columbia Gas*, 628 F.2d at 593.

dence, including the comments from experts at the Federal Trade Commission (the "FTC") and ISOs/RTOs, demonstrates that current levels of DR compensation are adequate, and that the Final Rule will ***overcompensate***[113] DR resources by subsidizing DR at the expense of other market participants and competing suppliers.[114]

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[113] *See, e.g.*, Comment of the Federal Trade Commission at 6, Docket No. RM10-17-000 (filed May 13, 2010) ("FTC Comments") (agreeing that commenters' "concern about overcompensation is well founded."); Comment of the Federal Trade Commission at 4, Docket No. RM10-17-000 (filed Oct. 13, 2010) (noting that even commenters supporting the proposal in the NOPR "implicitly recognize that the payment of full LMP constitutes overcompensation for demand response providers who pay flat retail rates."); Moeller Dissent at 4 (noting that under the Final Rule a DR Resource would receive "total compensation of LMP+G"); Comment on Notice of Proposed Rulemaking of PJM Interconnection, L.L.C. at 2, Docket No. RM10-17-000 (filed May 13, 2010) ("PJM Comments"). Several other commenters characterized payment of full LMP as the equivalent of providing DR customers with a free call "option to sell power they never purchased at a full LMP market price." PJM Comments at 6. *See also* Midwest ISO Comments at 6-7; EEI Comments at 4.

[114] *See, e.g.*, NYISO Comments at 7 (payment of full LMP overcompensates DR "at the expense of non-participating customers and other competing technologies not eligible for the subsidy"). At least one DR provider publicly admitted that payment of full LMP can be a subsidy, albeit one that it considers appropriate. *See, e.g.*, Comments of CPower, Inc. at 2-3, Docket No. RM10-17-000 (filed May 13, 2010).

As detailed in EPSA's reply comments,[115] there was basic agreement across the spectrum of stakeholders (including ISOs/RTOs, federal and State regulators, LSEs, generators, and consumer groups) that the efficient level of DR compensation is LMP with an offset to reflect the avoided costs of retail energy purchases (or "G").[116] With the exception of the Southwest Power Pool, Inc. (which does not currently have

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[115] *See* EPSA Reply Comments at 31-33.

[116] *See, e.g.*, APPA/NRECA Comments at 9-10; Comments of Samuel Newell, Kathleen Spees and Philip Q. Hanser at 5, Docket No. RM10-17-000 (filed May 13, 2010); Comments of Calpine Corporation at 3, Docket No. RM10-17-000 (filed May 13, 2010) ("Calpine Comments"); Comments of Exelon Corporation at 6, Docket No. RM10-17-000 (filed May 13, 2010) ("Exelon Comments"); FTC Comments at 2; Comments of Independent Power Producers of New York, Inc. at 3, Docket No. RM10-17-000 (filed May 13, 2010) ("IPPNY Comments"); Comments of the Organization of MISO States at 4, Docket No. RM10-17-000 (filed May 13, 2010) ("OMS Comments"); P3 Comments at 3; Comments of the Public Utilities Commission of Ohio at 3, Docket No. RM10-17-000 (filed May 13, 2010) ("PUC Ohio Comments"). Notably, all of the ISOs/RTOs and their independent or external market monitors agreed that payment of full LMP would overcompensate DR and/or that the Commission should permit ISOs/RTOs to include a retail offset. See Comments of the California Independent System Operator Corporation at 3, Docket No. RM10-17-000 (filed May 13, 2010) ("CAISO Comments"); ISO-NE Comments at 3-4; Midwest ISO Comments at 3-4, 9; NYISO Comments at 1; Comments of Potomac Economics, Ltd. at 4, Docket No. RM10-17-000 (filed May 13, 2010) ("Potomac Economics Comments"); PJM Comments at 6; Comments of the Independent Market Monitor for PJM at 2, Docket No. RM10-17-000 (filed May 13, 2010) ("PJM IMM Comments").

an economic DR program), all ISOs/RTOs pay DR at least this amount, if not more.[117] Moreover, while the Commission assumes that increasing compensation will necessarily increase investment and thereby participation of DR,[118] the Commission has not established that "the overpayment inherent in" paying full

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[117] Specifically, PJM and the Midwest ISO pay LMP with an offset for avoided retail costs, while the California Independent System Operator Corporation (the "CAISO"), ISO-NE, and the NYISO pay LMP under certain circumstances. *See, e.g.*, NOPR, FERC Stats. & Regs. ¶ 32,656 at P 8; Final Rule, FERC Stats. & Regs. ¶ 31,322 at P 14. While the CAISO and the NYISO currently pay DR LMP at the wholesale level, both support the use of an offset for avoided retail costs. As explained by the CAISO, the California Public Utilities Commission (the "CPUC"), the CAISO and stakeholders recognized the need for a retail offset to address the "double payment" and "missing money" problems at the retail level, but decided that these issues are best addressed by the relevant retail regulatory authority. Consequently, the CAISO DR compensation rules provide that issues such as the retail offset are to be addressed through bilateral agreements or by retail regulatory authorities, rather than through the CAISO settlement process. *See* Comments of the California Independent System Operator Corporation at 4-7, Docket No. RM10-17-000 (filed Oct. 13, 2010); *California Indep. Sys. Operator Corp.*, 132 FERC ¶ 61,045 at PP 27-29 (2010) (order conditionally accepting and describing the CAISO's currently effective DR compensation rules). Similarly, while the NYISO currently pays DR full LMP, subject to a $75/MWh minimum bid requirement, the NYISO supported the LMP-G alternative and urged the Commission to permit each ISO/RTO to work with its stakeholders to develop the details for implementing this approach to DR compensation. *See* NYISO Comments at 3.

[118] Final Rule, FERC Stats. & Regs. ¶ 31,322 at P 59.

LMP "will foster further investment rather than act as a mere windfall" to DR providers.[119] Further, as discussed in more detail below, the Final Rule's net benefits test and cost allocation mechanism are inevitable results of its decision to overcompensate DR by paying full LMP, a point that the Commission did not, and cannot, dispute.[120]

Moreover, the Final Rule ignored the arguments made by a number of commenters that DR revenues from participation in capacity and other markets must be taken into account in assessing the adequacy of DR compensation. DR participation and compensation in capacity markets has increased dramatically in recent years.[121] For example, since 2006 the amount of DR capacity participating in PJM's markets has increased seven-fold,[122] and capacity payments to DR resources

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[119] NYISO Comments at 3. This concern is particularly credible with respect to third-party DR providers that may not be required to use the increased DR revenues to lower their customers' bills.

[120] While the Commission described the net benefits test using different terms, at bottom, the purpose of the test is to assure that the amount of uplift paid by energy buyers to overcompensate DR resources does not exceed the savings from DR's suppression of LMPs. *See, e.g.*, Final Rule, FERC Stats. & Regs. ¶ 31,322 at P 53 ("the Commission requires the use of the net benefits test described herein to ensure that the overall benefit of the reduced LMP that results from dispatching demand response resources exceeds the cost of dispatching those resources.").

[121] *Id.* at P 85.

[122] As of May 2010 (*i.e.*, date comments submitted), DR capacity participating in PJM's capacity market has increased seven-fold

increased more than 100 percent just from 2008 to 2009.[123] The CAISO, ISO-NE, and the NYISO have also seen substantial increases in DR participation and capacity revenues.[124] In any case, capacity markets are likely to be much more significant revenue sources for DR than energy or ancillary services markets, because DR resources will not, and cannot, be dispatched as frequently as generators.[125] The Final Rule, however, simply ignored arguments that the Commission should take into account DR revenues from other markets in assessing the adequacy of current DR compensation,[126] and is, therefore, not the product of reasoned decisionmaking.[127]

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since 2006, from 1,245 to 7,294 MWs, while the number of DR providers in PJM has increased to 60. PJM Comments at 4.

[123] While payments from PJM's Economic Load Response Program decreased by $26 million from 2008 to 2009 (from $27.7 million to $1.2 million), DR capacity market revenue increased from $141 million in 2008 to $303 million in 2009 (a 114 percent increase). Total DR payments from energy, capacity, and ancillary services increased 77 percent from 2008 to 2009, from $174 million to $308 million. *See* PJM IMM Comments at 10.

[124] In ISO-NE, the amount of DR resources increased by 17 percent in 2009, while total compensation increased by more than 25 percent. *See* EPSA Reply Comments at 14-16.

[125] *See, e.g.*, CAISO Comments at 9 ("the economics of [DR] [are] largely driven by capacity payments, not energy rents.").

[126] The Commission addressed comments regarding DR's capacity market revenues solely in the context of the net benefits test namely, in rejecting comments that the net benefits test should account for effects in capacity markets. *See* Final Rule, FERC Stats. & Regs. ¶ 31,322 at P 85. The Commission never responded

Third, the Commission claimed that "paying LMP can address the identified barriers to potential demand response providers."[128] The Commission did not, however, demonstrate how or why overcompensating DR at the wholesale level would eliminate these barriers to entry, which, as even the Commission acknowledged, are at the retail level or are due to the disconnect between wholesale and retail rates.[129] The Final Rule will do nothing to eliminate what PJM's IMM describes as the "fundamental barrier" to entry, namely, that customers "do not know and do not pay the market price for wholesale power," and instead "pay a

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to commenters that, like EPSA, urged the Commission to look at all DR revenue sources in considering the adequacy of existing ISO/RTO rules governing DR compensation.

[127] *See, e.g.*, *CAPP*, 254 F.3d at 299 ("[u]nless the Commission answers objections that on their face seem legitimate, its decision can hardly be classified as reasoned.").

[128] Final Rule, FERC Stats. & Regs. ¶ 31,322 at P 58. *See also id.* at P 59 ("[r]emoving barriers to demand response will lead to increased levels of investment in and thereby participation of demand response resources (and help limit potential generator market power), moving prices closer to the levels that would result if all demand could respond to the marginal cost of energy.").

[129] *See id.* at P 57 (internal citations omitted) ("Barriers to demand response participation at the wholesale level identified by commenters include the lack of a direct connection between wholesale and retail prices, lack of dynamic retail prices . . . , the lack of real-time information sharing, and the lack of market incentives to invest in enabling technologies . "). *See also* Moeller Dissent at 10 (emphasis added) ("the lack of dynamic prices at the retail level is the ***primary*** barrier to [DR] participation.").

retail price that frequently bears only an attenuated relationship to the real time hourly LMP."[130] The Final Rule will not change this fact for the vast majority of retail customers (primarily, residential and commercial customers), who pay fixed retail rates and therefore are not exposed to LMPs.

In fact, the Final Rule may hinder efforts to overcome barriers to DR entry at the retail level by interfering with the development and implementation of more cost-effective and targeted retail reforms such as price-responsive demand ("PRD") that would eliminate the disconnect between retail and wholesale prices[131] and, consequently, the need for DR programs at the wholesale level altogether.[132] By retarding the

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[130] PJM IMM Comments at 4.

[131] *See also, e.g.*, Midwest ISO Comments at 15 (explaining that "[e]conomic demand response programs only exist to compensate for the disconnect between retail and wholesale rates. Fixing retail tariffs is an obvious and more cost-effective alternative to economic demand response programs.").

[132] *See, e.g.*, PJM IMM Comments at 5 (explaining that "[t]he entire demand side program exists only because of the disconnect between wholesale and retail rates. The assertion that the program design should not account for the details of the retail rate design leads to the conclusion that there should be no demand side program at all"); Comments of the Pennsylvania Public Utilities Commission at 1, Docket No. RM10-17-000 (filed May 13, 2010) ("Pennsylvania PUC Comments") (noting that payments to DR "by ISOs and RTOs and associated ISO/RTO administrative measurement and verification structures are inherently interim measures. The ultimate goal of these interim measures is the development of fully competitive wholesale and retail markets that permit end-use

development of PRD, the Final Rule threatens to frustrate the shared goal of facilitating DR deployment and to perpetuate indefinitely the federal intrusion into State retail ratemaking. The Final Rule contains no explanation as to why the Commission chose such a blunt, and ineffective, instrument to promote DR participation, rather than identifying specific barriers to entry at the wholesale level and individually mandating their removal.

Fourth, the Final Rule suggested that paying DR full LMP is necessary to overcome barriers to entry by DR resources,[133] but the Commission has provided no explanation, and has cited no evidence, establishing that the amount of the subsidy being provided is tailored to, or, indeed, has any connection with, what is needed to overcome those barriers. Nor has the Commission explained why setting the subsidy at this level would overcome these barriers to entry, which, as noted above, are at the retail level and are due to the disconnect between wholesale and retail rates. Moreover, while many of these barriers to entry appear to be transient in nature,[134] the Final Rule con-

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customers to see and react directly to market prices without centralized measurement, verification, supervision and control.").

[133] *See* Final Rule, FERC Stats. & Regs. ¶ 31,322 at P 58 ("[t]he Commission concludes that paying LMP can address the identified barriers to potential demand response providers.").

[134] *See* NOPR, FERC Stats. & Regs. ¶ 32,656 at P 22 (acknowledging that "markets, and the types of demand response participating in them, continue to evolve" and that it may, therefore, "be

tains no mechanism for decreasing the subsidy—and the corresponding burden on other market participants—as these barriers fall.

2. The Commission Has Failed To Establish That The Final Rule Will Produce Just And Reasonable Rates Or To Respond To Objections Concerning The Detrimental Impacts Of The Final Rule.

The Commission has also failed to demonstrate that its proposed solution to the "problem" of inadequate DR compensation—paying DR full LMP—is just and reasonable, which may be because the starting point for the Commission's analysis was a "presumption" that payment of full LMP is the "correct result."[135] Nor has it adequately responded to, or rebutted, the overwhelming evidence that the Final Rule conflicts "with the Commission's efforts to promote competitive markets and with its statutory mandate to ensure" that jurisdictional rates are just and reasonable.[136] Moreover, as the Competitive Supplier Associations and other commenters emphasized, by overcompen-

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necessary in the future for industry and the Commission to reassess the appropriate method for compensating demand response resources in organized wholesale energy markets"). *See also id.* at P 18-19 & n.46 (describing the "current barriers to demand response" and the "***evolving*** nature of the technology enabling demand response" and characterizing full LMP as the "correct approach ***at this time***") (emphasis added).

[135] *See, e.g.*, Tech. Conf. Tr. at 7:19-8:5 (Chairman Wellinghoff).

[136] Moeller Dissent at 1.

sating DR and suppressing LMPs, the Final Rule will produce perverse incentives, distort consumption and production decisions in the short-term and investment decisions in the long-term, and, ultimately, increase costs to consumers and harm reliability. By failing to respond meaningfully to the legitimate concerns raised by commenters and by Commissioner Moeller in his dissenting statement, the Commission failed to fulfill its duty to engage in reasoned decisionmaking.[137]

While the Commission acknowledged in the Final Rule that payment of full LMP in all hours would not be cost-effective,[138] and that the increased costs from overcompensating DR must be allocated to other market participants,[139] its proposed fixes—the net benefits test, cost allocation mechanism, and measurement and verification standards—will create a host of new problems that could have easily been avoided through adopting the efficient pricing mechanism advocated by all of the ISOs/RTOs and many other commentators (*i.e.*, LMP with an offset for the avoided costs of fore-

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[137] *See, e.g., AGA*, 593 F.3d 14, 20-21.

[138] *See* Final Rule, FERC Stats. & Regs. ¶ 31,322 at P 53 (finding that, due to the "billing unit effect," it would not be cost-effective to pay DR LMP in all hours, and that the Commission will "require[] the use of the net benefits test described herein to ensure that the overall benefit of the reduced LMP that results from dispatching those resources.").

[139] *See id.* at P 99 (explaining that increasing DR compensation will produce a "negative balance" in ISOs/RTOs net revenues "that must be addressed through cost allocation.").

gone retail purchases). The need for these fixes is an inevitable consequence of the Commission's decision to overcompensate DR resources,[140] which increases total resource costs for serving load that must then be allocated to other customers.[141] As the FTC explained:

> [T]here is no need for a net benefits test so long as [the Commission] utilizes efficient prices in compensating demand response providers, because efficient prices will elicit efficient levels of demand response. The proposal to implement a net benefits test as a screen arises as a policy issue only if [the Commission] sets inefficiently high compensation levels for demand response.[142]

The Midwest ISO reached a similar conclusion:

> [O]vercompensating DR will result in an artificial market construct in which LMP is suppressed below the price at which generation resources will voluntarily bid into the energy market. This will not only reduce the economic efficiency of the wholesale market, it will also unfairly shift the costs resulting from the inefficient curtailment to those retail customers who do not participate in DR

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[140] *See, e.g.*, PJM Comments at 9-11 (explaining that payment of full LMP results in large cost shifts among market participants and necessitates cost allocation mechanisms).

[141] *See, e.g.*, *id.* at 8-9; ISO-NE Comments at 3.

[142] FTC Comments at 1.

> (typically small residential and commercial customers).[143]

Moreover, as discussed in further detail in Section III.B.7 below, current measurement and verification standards are not sufficient to ensure that DR providers have actually reduced consumption in response to price signals, or to prevent DR providers from fraudulently collecting DR payments though "load shifting" and similar manipulative strategies.

Over and above the problems that the Commission acknowledged, its approach creates a number of other problems that are not addressed in the Final Rule. In particular, paying DR LMP, without a retail offset, is inefficient, conflicts with least-cost dispatch (which is a fundamental market design element of all ISO/RTO markets), harms long-run reliability, and will hinder the development of more cost-effective retail reforms such as PRD. Commenters across the spectrum recognized that any short-run cost savings from the suppression of LMPs would likely be more than outweighed by cost increases over the long-run, and would therefore ultimately harm consumers. As Commissioner Paul Centolella of the Ohio Public Utilities Commission put it:

> Any unnecessarily large incentives for demand response have a cost. The amount of any incentives

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[143] Comments of the Midwest Independent Transmission System Operator, Inc. at 3, Docket No. RM10-17-000 (filed Oct. 13, 2010) ("Midwest ISO Post-Conference Comments").

> will be recovered from other consumers. While the discussion of a "net benefits" test has focused on the potential for additional demand response to lower prices in energy markets, lower energy market prices do not necessarily mean lower total costs to consumers. RTO capacity prices typically include an offset for energy and ancillary service revenues. Lower energy market prices will tend to increase capacity prices.[144]

Commissioner Moeller echoed these concerns in his dissenting statement, concluding that the Commission's determination, which is "unencumbered by 'textbook economic analysis of the market subject to [its] jurisdiction,'"[145] will create "inefficiencies [that] will result in customers experiencing a short-term benefit by way of a lower LMP, but will also impose long-term costs on the energy markets."[146] ISO-NE conducted an analysis of the Final Rule's long-term effects on capacity markets, and found "that capacity price increases from the suppression of energy prices driven by paying demand response the full LMP can fully offset energy price reductions, making consumers

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[144] Comments of Commissioner Paul A. Centolella of the Public Utilities Commission of Ohio Supplementing His Technical Conference Remarks at 9-10, Docket No. RM10-17-000 (filed May 13, 2010).

[145] Moeller Dissent at 9 (*quoting* Final Rule, FERC Stats. & Regs. ¶ 31,322 at P 46).

[146] *Id.* at 9-10.

worse off in the end."[147] Moreover, by suppressing LMPs below the efficient levels, the Final Rule will distort investment incentives and harm reliability in the long-run by encouraging existing supply to exit and discouraging new entry.[148] The Commission did not even begin to respond to these arguments, rendering its determination arbitrary and capricious.[149]

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[147] ISO-NE Comments at 15. *See also* Comments of Midwest TDUs at 7, Docket No. RM10-17-000 (filed May 13, 2010) ("Midwest TDUs Comments") ("resulting distortions in the markets, and the potential that this LMP reduction would be offset by increased capacity costs, making consumers worse off"); EEI Comments at 2-3 ("overusing demand response to artificially depress market energy prices through subsidies will yield temporary benefits for LSEs and some large commercial and industrial customers but ultimately will raise wholesale market prices.").

[148] ISO-NE Comments at 29. According to ISO-NE, payment of full LMP will distort investment incentives by discouraging investment in renewable generation technologies like wind that have low or no fuel costs and in high capacity-factor DR resources like energy efficiency. *Id.* at 30.

[149] *See, e.g., PPL Wallingford*, 419 F.3d at 1199-1200 (vacating and remanding orders for Commission's failure to respond to "answer objections that on their face seem legitimate") (*quoting CAPP*, 254 F.3d 299). As noted above, the Commission brushed aside arguments that the net benefits test should consider the impact of the rule on capacity markets by stating that the Final Rule "is focused on only on organized wholesale energy markets, not capacity markets." Final Rule, FERC Stats. & Regs. ¶ 31,322 at P 85. The Commission did not, however, specifically respond to concerns that payment of LMP—in and of itself and without regard to the implementation of a net benefits test—will distort long-term

Overcompensating DR threatens to distort consumption and production decisions as well, both in wholesale power markets and in the broader economy, increasing total resource costs and reducing economic output and social welfare. As ISO-NE observed, "[b]y dispatching higher-cost [DR] resources, lower-cost generating resources are displaced, which is inefficient and increases total resource costs in the energy market."[150] This is not only inefficient, but it "runs counter to the fundamental least-cost resource dispatch procedure of the energy markets, and will ultimately raise consumer costs,"[151] and is thus inconsistent with one of the central features of the competitive market design. Notably, market monitors for ***all*** of the ISOs/RTOs with economic DR programs raised serious concerns regarding the market inefficiencies that would result from the Commission's proposal in the NOPR.[152]

The approach adopted in the Final Rule will distort price signals in a manner that will cause some customers to reduce consumption below optimal levels and others to increase consumption above optimal levels.

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investment incentives and result in increased costs to consumers in the long run.

[150] ISO-NE Comments at 3.

[151] *Id.* at 2.

[152] *See* Comments of the ISO New England Inc. Independent Market Monitor at 5-7, Docket No. RM10-17-000 (filed May 13, 2010) ("ISO-NE IMM Comments"); PJM IMM Comments at 2; Potomac Economics Comments at 9-10.

Commissioner Moeller explained that, as a result of the suppressed LMPs, "the price signal sent to customers will be that the cost of power is cheaper so they may decide to use more power even though the real cost of producing that power is now higher."[153] The FTC elaborated on this theme, explaining that:

> Customers who pay for the power they consume, but not the power that they sell back to the grid, will have an incentive to consume power not when the marginal benefit exceeds the marginal cost, but when the marginal benefit exceeds the sum of the marginal cost and the retail price. Simple algebra shows that buying when the difference between the marginal benefit and the retail price exceeds the marginal cost is equivalent to buying when the marginal benefit exceeds the sum of the retail price and the marginal cost. Thus, giving away for free the power that customers resell implicitly raises the price of consuming power above the efficient level. This will lead firms to provide too much demand response.[154]

The resulting market distortions will extend beyond the power markets. APPA and NRECA asked:

> [W]hether it is always best from a societal standpoint for industrial plants to cease production and commercial activities to be curtailed so that de-

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[153] Moeller Dissent at 9. *See also* ISO-NE Comments at 30.

[154] FTC Comments at 7.

> mand response revenues can be earned, especially when the incentive rates they are responding to are not economically efficient in the first instance. These actions may be profit-maximizing for the individual industrial/commercial concerns in question, but may come at the price of decreased wages, less desirable working hours and a lower level of economic activity in the affected communities.[155]

Putting it somewhat more bluntly, but no less accurately, Commissioner Moeller warned that the Final Rule "could have job-killing results."[156]

Finally, rather than eliminating the market imperfections that have hindered efficient pricing at the retail level, the Final Rule will hinder the development of retail dynamic price response programs such as PRD and other State DR reforms.[157] These reforms

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[155] Post-Technical Conference Comments of the American Public Power Association at 3, Docket No. RM10-17-000 (filed Oct. 13, 2010).

[156] March 17, 2011 Commission Meeting Tr. at 12:9-11.

[157] *See, e.g.*, CAISO Comments at 4; Notice of Intervention, Comments and Request for Clarification of the Public Utilities Commission of the State of California Regarding the Proposed Rulemaking on Demand Response Compensation in Organized Wholesale Markets at 9-10, Docket No. RM10-17-000 (filed May 13, 2010) ("CPUC Comments"); Comment of the Delaware Public Service Commission at 2, Docket No. RM10-17-000 (filed May 13, 2010); FTC Comments at 8; ICC Comments at 3; ISO-NE IMM Comments at 5-6; Midwest TDUs Comments at 13; Ohio PUC Comments at 5; OMS Comments at 4; PJM Comments at 5-6; PJM IMM Comments at 5. *See also* Calpine Comments at 4, Com-

at the retail level are more narrowly targeted and cost-effective, and they have the potential to eliminate altogether the disconnect between wholesale and retail rates, rendering wholesale DR programs obsolete.[158] The Final Rule will discourage State regulators from pursuing PRD and other initiatives at the retail levels. As the ICC explains:

> [A]s the value of the subsidy increases, the state commission's likelihood of implementing time-differentiated retail rates decreases. ***It should be recognized that retail rates reflecting wholesale prices would be the most efficient means of allocating the scarce energy resources.*** Specifically, subsidizing demand reductions has the effect of decreasing the potential for retail rate reform.[159]

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ments of Capital Power Corporation at 6, Docket No. RM10-17-000 (filed May 13, 2010); Comment of the Detroit Edison Company at 4, Docket No. RM10-17-000 (filed May 13, 2010); Comments of Dominion Resources Services, Inc. at 7-8, Docket No. RM10-17-000 (filed May 13, 2010); Comment of Duke Energy at 4, Docket No. RM10-17-000 (filed May 13, 2010); EEI Comments at 22; Exelon Comments 4; Comments of Old Dominion Electric Cooperative at 6, Docket No. RM10-17-000 (filed May 14, 2010); NEPGA Comments at 2; Comments of RRI Energy, Inc. at 2, Docket No. RM10-17-000 (filed May 13, 2010).

[158] *See, e.g.*, Pennsylvania PUC Comments at 4.

[159] ICC Comments at 14 (emphasis added). *See also* CPUC Comments at 6 ("promulgating a uniform national rule at this time may inadvertently impede the implementation of the optimal demand response compensation for an individual ISO or RTO which addresses the needs of that particular region.").

Moreover, the Commission-mandated subsidy makes DR participation at the wholesale level much more lucrative than solutions at the retail level like PRD, and will likely discourage participation in these programs.[160] According to the NYISO, paying full LMP "may create an incentive for such customers to avoid moving to retail dynamic pricing—the preferable rate structure for recognizing the economic value of load vis a vis generation,"[161] while new, innovative technologies "may be kept out of the market by [DR] that would be uneconomic at LMP-G but participates when subsidized at full LMP."[162] In addition, as a result of the Commission's action, State regulators would, "[i]ronically be faced with the task of revising retail rate structures in order to correct a price distortion created by a wholesale market pricing mechanism which was intended to improve price signals,"[163] wasting time and resources that they might have otherwise directed towards adopting needed reforms in the retail market. In the Final Rule, the Commission did not even respond to concerns that its own efforts to elimi-

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[160] *See* PJM Comments at 23. *See also* EEI Comments at 22 ("[t]he Commission should exercise restraint from prescribing uniform standards for wholesale demand response programs that could potentially impede the continued development of demand response at the retail level.").

[161] NYISO Comments at 12.

[162] *Id.* at 15.

[163] OMS Comments at 3-4.

nate barriers to entry by DR would hinder reforms at the retail level.

3. The Final Rule Departs Without Adequate Explanation From Existing Precedent That Subsidies Are Not Necessary To Incent DR Participation.

In the Final Rule, the Commission departed, without adequate explanation, from long-standing Commission precedent for the proposition that permanent subsidies are not necessary to promote DR, and as such its action was arbitrary and capricious.[164] In *PJM ICC*, for example, the Commission rejected a complaint seeking to require PJM to continue to pay subsidies that were set to expire to incentivize DR participation. The Commission properly recognized payment of full LMP as a subsidy and found that payment of LMP minus the retail rate was sufficient incentive for DR participation.[165] The Commission further found that "because these customers are paying the applicable wholesale price, they already have an incentive to curtail load,"[166] and that the complainants had "provided no evidence showing that the subsidy payments were needed to ensure just and reasonable rates."[167] Similarly, in *PJM Interconnection*,

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[164] *See, e.g., Fox*, 129 S. Ct. at 1811; *Greater Boston*, 444 F.2d at 852.

[165] *PJM ICC*, 121 FERC ¶ 61,315 at P 26.

[166] *Id.*

[167] *Id.*

L.L.C.,[168] the Commission accepted PJM's proposal to pay DR LMP minus the retail rate, and rejected protesters' arguments that DR should receive full LMP. The Commission explained that "[t]he purpose of a load response program is to try to duplicate what a customer reducing power would receive in an unregulated market where the customer's price reflects the LMP."[169] In such an unregulated market, a customer that reduced consumption would receive a benefit: namely, LMP. To replicate that result, the Commission agreed that "PJM should compensate the customer by paying the difference between the LMP and what the customer would save by not using power (the retail price it didn't have to pay)."[170]

4. The Commission's Determination That The Final Rule Is Necessary To Ensure That ISO/RTO Rates Are Just And Reasonable Is Contrary To Law, Because It Ignores Regulated Sellers' Statutory And Constitutional Rights To Just And Reasonable Compensation.

The Commission appears to have ended this rulemaking with the same dubious "presumption" that paying DR resources full LMP is the "correct result" with which it "started,"[171] concluding that it "is necessary to ensure that rates are just and reasonable in the

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[168] 99 FERC ¶ 61,227 (2002).

[169] *Id.* at 61,941.

[170] *Id.*

[171] Tech. Conf. Tr. at 7:20-25 (Chairman Wellinghoff).

organized wholesale energy markets,"[172] and that "payment by an RTO or ISO of compensation other than the LMP is unjust and unreasonable."[173] In reaching these conclusions, however, the Commission made no attempt to quantify the amount by which jurisdictional rates are excessive or may become excessive in the absence of the Final Rule,[174] the effect of increased DR compensation on lowering jurisdictional rates, or the net effect of the Final Rule jurisdictional sellers' compensation. Instead, it appears that the Commission has blithely and falsely assumed that more DR, more mitigation, and lower prices are always better. By solely focusing on the potential for DR to lower prices, however, without regard to whether these rates will be compensatory or confiscatory, the Commission has abdicated its duties under the FPA and the U.S. Constitution to ensure that rates for jurisdictional sales are just and reasonable as to jurisdictional public utilities making those sales. Moreover, the Commission has ignored not only its statutory obligations to regulated sellers, but also the statutory language itself, in "somehow equating the concept of a

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[172] Final Rule, FERC Stats. & Regs. ¶ 31,322 at P 2.

[173] *Id.* at P 47.

[174] In fact, the evidence in the record indicates that energy prices fell to record lows in 2009 and have remained at historically low levels since then. *See* Commission 2009 SOM Report at 7 ("[w]ith lower electricity prices and lower fuel costs, electricity prices fell by half" from 2008 to 2009).

just and reasonable rate with a lower price."[175] The Commission has thus subordinated the indisputable right of jurisdictional public utilities to just and reasonable compensation for jurisdictional wholesale sales to an alleged right of non-jurisdictional DR providers to higher compensation for non-jurisdictional, retail non-purchases.[176]

Federally regulated entities' right to receive compensatory rates is grounded in the Fifth Amendment of the U.S. Constitution,[177] which prohibits takings of private property for public use without just compensation.[178] The Supreme Court has held that the constitutional right to just compensation is coextensive with the statutory requirement[179] that such rates must, at a

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[175] Moeller Dissent at 7.

[176] Further, as noted above, the fact that the Final Rule is so ill-suited to addressing the actual barriers to DR entry, combined with the Commission's single-minded focus on lowering prices without regard to whether rates paid to regulated sellers are just and reasonable, begs the question of whether the purpose of the Final rule is simply to subsidize a favored group (i.e., DR providers) at the expense of generators and to lower prices by any means necessary. As such, the Commission's action "constitutes arbitrary and capricious conduct that cannot stand." *See, e.g., Woods Petroleum*, 18 F.3d at 860.

[177] U.S. Const. amend V, cl. 3.

[178] *See, e.g., Smyth v. Ames*, 169 U.S. 466, 546 (1898); *Bluefield Waterworks & Imp. Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679, 690 (1923) ("*Bluefield*").

[179] *Hope* was decided under Sections 4 and 5 of the NGA, 15 U.S.C. 717c, 717d (2006). As noted, decisions interpreting these

minimum, provide a reasonable opportunity for the utility to recover of, and on, its investment.[180] In this regard, the setting of "just and reasonable" rates "involves a balancing of the investor and the consumer interests."[181] Rates must provide "enough revenue not only for operating expenses but also for the capital costs of the business"[182] and be sufficient for the utility to "maintain its credit and attract capital."[183] The fixing of just and reasonable rates is thus a two-way street: regulated sellers are prohibited from charging exploitative rates, and in return, they have a right to receive compensatory rates. In the Final Rule, the Commission seemingly made no effort to balance investor and consumer interests, and instead applied a heavy, regulatory thumb on the scale in favor of the latter and to the detriment of the former.

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provisions may be "cite[d] interchangeably" with decisions interpreting Sections 205 and 206 of the FPA, 16 U.S.C. §§ 824d, 824e (2006). *Arkla*, 453 U.S. at 577 n.7.

[180] *Hope*, 320 U.S. at 607. The Supreme Court reached a similar conclusion regarding just compensation under the Fourteenth Amendment, U.S. Const. amend. XIV, § 1. *See Bluefield*, 262 U.S. at 692-693.

[181] *Hope*, 320 U.S. at 603. *See also Grand Council of the Crees v. FERC*, 198 F.3d 950, 956 (D.C. Cir. 2000) (explaining that "'the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated,' while there is a 'consumer interest in being charged non-exploitative rates.'") (internal citations omitted).

[182] *Hope*, 320 U.S. at 603.

[183] *Id.*

A single-minded focus on lowering jurisdictional rates, like that which appears to underlie the Final Rule, is fundamentally at odds with the Commission's constitutional and statutory obligations to regulated entities, including the public utility members of the Competitive Supplier Associations. The conflict with the Commission's obligations is all the more glaring in light of the Final Rule's inordinate concern for whether unregulated DR service providers are receiving "just and reasonable" compensation for non-jurisdictional services without sufficient regard for whether the payment of full LMP to DR will produce just and reasonable rates for jurisdictional sellers'.

In the ISO/RTO setting, the Commission has applied *Hope*'s directive that rates must be sufficient to cover capital costs and to attract capital to mean that just and reasonable rates must be sufficient to ensure an adequate supply of generation. This is because, in competitive markets, as under the traditional regulatory paradigm, sufficient rates serve both consumers' and investors' interests, as they are necessary to maintain reliability.[184] In fact, the Commission has applied this principle from *Hope* as a cornerstone design element for organized markets by requiring ISOs

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[184] *See, e.g., San Diego Gas & Elec. Co.*, 93 FERC ¶ 61,121 at 61,358 (2000) (explaining that in competitive power markets, where "supply is driven by market price instead of regulatory requirements, ratepayer interests may no longer depend solely on whether current prices are deemed too high, but also on whether prices are too low to elicit new supplies over time.").

and RTOs to adopt measures to limit or prevent subsidized, uneconomic entry because such entry can reduce prices to below a just and reasonable level. For example, in unanimously accepting NYISO's proposed buyer market power mitigation rule,[185] the Commission explained that:

> While a strategy of investing in uneconomic entry and offering it into the capacity market at a low or zero price may seem to be good for customers in the short-run, it can inhibit new entry, and thereby raise price and harm reliability, in the long-run. Under the FPA, the Commission must ensure that rates are just and reasonable. The courts have long held that establishing just and reasonable rates involves a balancing of consumer and investor interests.[186]

Moreover, the Commission has acknowledged that it is "statutorily mandated" to prevent such uneconomic entry[187] because such uneconomic entry "can produce unjust and unreasonable wholesale rates by artificially depressing" clearing prices.[188] The Commission has

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[185] *See, e.g., New York Indep. Sys. Operator, Inc.*, 122 FERC ¶ 61,211 at P 100 ("*NYISO I*"), *on reh'g & compliance*, 124 FERC ¶ 61,301 (2008), *on reh'g*, 131 FERC ¶ 61,170 (2010) ("*NYISO II*").

[186] *NYISO I*, 122 FERC ¶ 61,211 at P 103 (*citing Hope*).

[187] *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,022 at P 143 (2011) ("*PJM*").

[188] *Id.* at P 141. *See also NYISO II*, 124 FERC ¶ 61,301 at P 29 ("all uneconomic entry has the effect of depressing prices below the

approved similar buyer-side mitigation rules, for the same reasons, in PJM, NYISO, and ISO-NE.[189] But despite these rules, ISO/RTO rates, particularly with respect to capacity markets, have already fallen well below the minimum level necessary for suppliers to cover their fixed costs and to attract new capital. The Final Rule threatens to reduce ISO/RTO rates still further below compensatory levels.

5. To The Extent The Commission Found That Existing ISO/RTO Mitigation Is Inadequate, Its Determination Is Arbitrary And Capricious, Unsupported By Substantial Evidence, And Contrary To Law.

The Final Rule concludes that payment of full LMP to DR is necessary to ensure that ISO/RTO rates are just and reasonable because, among other things, increased DR participation can lower prices and mitigate supplier market power.[190] The Commission's repeat-

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competitive level and . . . this is the key element that mitigation of uneconomic entry should address.").

[189] *See PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331 at PP 103-104 (2006), *on reh'g and clarification and compliance*, 119 FERC ¶ 61,318 at P 165 (2007); *Devon Power LLC*, 115 FERC ¶ 61,340 at PP 113, 115, *reh'g denied*, 117 FERC ¶ 61,133 (2006).

[190] Final Rule, FERC Stats. & Regs. ¶ 31,322 at PP 10, 47. *See also* NOPR, FERC Stats. & Regs. ¶ 32,656 at P 13 (asserting that rates in ISO/RTO markets may have become "unjust and unreasonable," and that the proposed subsidies to DR are needed "[t]o ensure that wholesale prices in ISOs and RTOs remain just and reasonable.").

ed emphasis on the need for increased DR participation to lower prices and mitigate market power in the NOPR and in the Final Rule strongly suggests that the Commission's decision was based on the unstated, unsupported and erroneous premise that existing ISO/RTO mitigation is inadequate. To the extent that the Commission relied on this unfounded assumption (even implicitly), its decision is not supported by any evidence in the record, much less the substantial evidence necessary to survive judicial review.[191] Of course, reliance on such an unstated assumption would also fall well short of satisfying the requirements of reasoned decisionmaking.[192]

It is disturbing that the Commission would so casually cast doubt on the justness and reasonableness of existing ISO/RTO market rules—all of which the Commission previously approved as just and reasonable—especially given its own repeated and consistent statements to the opposite effect. In Order No. 697-A, for

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[191] *See* 5 U.S.C. § 706(2)(E) (2006). *See also, e.g., ICC*, 576 F.3d at 477 (explaining that a reviewing court cannot "uphold a regulatory decision that is not supported by substantial evidence on the record as a whole.").

[192] *MoPSC I*, 234 F.3d 36 at 41 (remanding Commission order because the reviewing court found that "the record does not manifest that [the Commission] originally invoked all of the grounds it now relies on to support its action."). *See also id.* ("[a] passing reference to relevant factors, however, is not sufficient to carry out 'reasoned' and 'principled' decisionmaking. We have repeatedly required the Commission 'to fully articulate the basis for its decision.'") (*quoting Columbia Gas*, 628 F.3d at 593).

example, the Commission properly adopted, on a generic basis, a "rebuttable presumption that the existing [ISO/RTO] mitigation is sufficient to address any market power concerns."[193] Moreover, the Commission has consistently—and correctly—found that the existing mitigation in the various ISOs/RTOs is just and reasonable,[194] without reference to the level of DR compensation or participation, and organized markets have been shown to be competitive year after year by independent regional market monitors[195] and the Commission itself.[196]

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[193] Order No. 697-A, FERC Stats. & Regs. ¶ 31,268 at P 111.

[194] *See, e.g., Maryland Pub. Serv. Comm'n v. PJM Interconnection, L.L.C.*, 123 FERC ¶ 61,169, *order on reh'g*, 125 FERC ¶ 61,340 (2008) (order rejecting complaints regarding PJM's market power screen, the three-pivotal-supplier test, but finding that mitigated prices were inadequate); *Connecticut ex rel. Blumenthal, et al. v. ISO New England Inc.*, 117 FERC ¶ 61,038 (2006), *reh'g denied*, 118 FERC ¶ 61,205 (2007) (order denying complaint alleging, among other things, that ISO-NE's mitigation of units subject to the Peaking Unit Safe Harbor bidding rules was inadequate); *California Elec. Oversight. Bd. v. California Indep. Sys. Operator Corp.*, 109 FERC ¶ 61,182 (2004) (order denying complaint seeking to require the CAISO to adopt automatic mitigation procedures); *NSTAR Elec. & Gas Corp. v. Sithe Edgar, LLC*, 101 FERC ¶ 61,064 (2002) (order denying complaint that ISO-NE mitigation measures were inadequate to prevent units in an ISO-NE subregion from exercising market power).

[195] *See* 2010 PJM SOM Report at 3-7; CAISO Department of Market Monitoring, *2009 Annual Report on Market Issues and Performance* at 1 (issued April 2010), *available at*: http://www.caiso.com/2777/27778a322d0f0.pdf; ISO New England Internal

The Commission has not even hinted at what previously unrecognized flaw it has identified in existing ISO/RTO mitigation rules has caused it to conclude that those rules are unjust and unreasonable in the absence of the additional mitigation to be provided by increased DR compensation. In this regard, the Final Rule is an abrupt and unexplained departure from the vast body of Commission precedent finding that existing ISO/RTO mitigation is just and reasona-

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Market Monitor, 2009 Annual Markets Report at 2-4 (issued May 18, 2010), *available at*: http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/2009/index.html; Potomac Economics, Ltd., *2009 Assessment of the Electricity Markets in New England* at ix-x (issued June 2010), *available at*: http://www.potomaceconomics.com/uploads/isone_reports/ISONE_2009_IMMU_Report_Final.pdf; Potomac Economics, Ltd., *2009 State of the Market Report for Midwest ISO* at ii-iv (issued Aug. 2010), *available at*: http://www.potomaceconomics.com/uploads/midwest_documents/2009_State_of_the_Market_Report.pdf; Potomac Economics, Ltd., *2009 State of the Market Report: New York ISO* at iv-v (issued Sept. 2010), *available at*: http://www.potomaceconomics.com/uploads/nyiso_reports/NYISO_2009_Full_Text_Final.pdf; Boston Pacific Company, *2009 State of the Market Report: Southwest Power Pool, Inc.* at 7-8 (issued May 26, 2010), *available at*: http://www.bostonpacific.com/assets/documents/SPP2009SOMReport.pdf.

[196] *See, e.g.*, Federal Energy Regulatory Commission, Office of the Chairman, *Performance Metrics for Independent System Operators and Regional Transmission Operators*, at 8-9 (Apr. 2011).

ble,[197] and a quintessential example of arbitrary and capricious decisionmaking.[198]

Moreover, by requiring ISOs/RTOs to amend their tariffs to supplement existing mitigation measures, the Commission's action is contrary to law because the Commission did not find that any existing ISO/RTO mitigation measures are unjust and unreasonable. To require ISOs/RTOs to revise or supplement their existing, Commission-approved mitigation measures (or any other provision of their existing tariffs), the Commission would have had to satisfy the requirements of Section 206 of the FPA,[199] namely, by finding that the existing mitigation provisions are unjust and unreasonable and that its proposed replacement is just and

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[197] *See, e.g., Williams*, 475 F.3d at 322 (vacating Commission orders because the Commission "neither explained its action as consistent with precedent nor justified it as a reasoned and permissible shift in policy."); *Nuclear Energy Inst., Inc. v. EPA*, 373 F.3d 1251, 1296 (D.C. Cir. 2004) ("[i]f an agency decides to change course, however, we require it to supply a 'reasoned analysis indicating that prior policies and standards are being deliberately changed, not casually ignored.'") (internal citations omitted). *See also, e.g., Fox*, 129 S. Ct. at 1811; *Greater Boston*, 444 F.2d at 852.

[198] *See, e.g., PG&E Gas Transmission v. FERC*, 315 F.3d 383, 390 (D.C. Cir. 1989) (vacating Commission order where the Commission had "given no explanation whatsoever for this apparent shift in Commission policy. [The Commission's] failure to come to terms with its own precedent represents the absence of a reasoned decisionmaking process.").

[199] 16 U.S.C. § 824e (2006).

reasonable.[200] The Commission has not done so or even acknowledged the requirements of Section 206.

Further, the Commission failed to respond to the arguments raised by the Competitive Supplier Associations and others that payment of LMP to DR would likely result in over-mitigation, which, as the Commission has long recognized, can be just as harmful to competition as under-mitigation and may reduce regulated sellers' rates to unjust and unreasonable levels.[201] The Commission is required to strike a balance between inadequate mitigation and over-mitigation that "reflect[s] an appropriate trade-off between the interests of buyers and sellers"[202] and that allows generators "to charge prices that are high enough for them to recover their fixed costs."[203] In the Final Rule, the Commission failed to do so, or even to give serious consideration to suppliers' legitimate concerns regarding over-mitigation and unjustified price suppression, and is, therefore, arbitrary and capricious.[204]

In addition, the Final Rule is contrary to law, because it will facilitate, or even mandate, the exercise of

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[200] *See, e.g., Atlantic City*, 295 F.3d at 10; *Sea Robin Pipeline Co. v. FERC*, 795 F.2d 182, 183-184 (D.C. Cir. 1986) (interpreting requirements of the NGA analogue of FPA Section 206).

[201] *See* EPSA Comments at 45-46.

[202] *Wisconsin Public Power*, 493 F.3d at 262 (*citing Hope*, 320 U.S. at 603).

[203] *Id.* at 263.

[204] *See, e.g., Moraine Pipeline*, 906 F.2d at 9.

buyer market power to artificially suppress prices below just and reasonable levels.[205] Moreover, the Final Rule is arbitrary and capricious because it departs, without adequate explanation, from the precedent discussed above where it acknowledged its statutory mandate[206] and its constitutional obligation to mitigate buyer market power and because the Commission failed to respond meaningfully to the arguments of the Competitive Supplier Associations and others regarding buyer market power.[207] Professor Hogan summarizes these concerns as follows:

> In effect, this price mitigation service is not a policy to move towards a more competitive and efficient market. ***Rather, it would be an application of regulatory authority to enforce a buyers' cartel.*** The price mitigation policy would not be improving efficiency. ***Rather it would be merely employing government authority to transfer income from producers to consumers.*** Thus the pursuit of price mitigation

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[205] 16 U.S.C. §§ 824d, 824e (2006).

[206] *PJM*, 135 FERC ¶ 61,022 at P 143.

[207] *See, e.g.*, EPSA Reply Comments at 55; *See also* Reply Comments of the New England Power Generators Association, Inc. at 2-3, Docket No. RM10-17-000 (filed May 13, 2010) ("NEPGA Reply Comments"). The Commission also failed to consider whether measures to monitor or mitigate any increased buyer market power should have been included in the Final Rule. The risk of buyer market power is in fact heightened with respect to DR in light of the fact that many DR service providers will not be public utilities subject to the full scope of Commission requirements and sanctions for unlawful conduct.

> of this type would run contrary to the Commission's policy of supporting and facilitating efficient, non-discriminatory electricity markets.[208]

In fact, the Final Rule would institutionalize the collective exercise of buyer market power to artificially reduce prices below the competitive level through the net benefits test. As NEPGA explained, the Commission's net benefits test assesses whether it is economic (or "cost-effective") to pay DR LMP based on the "portfolio benefits" to other buyers or positions from the price suppression, rather than on a stand-alone basis.[209] In cases such as Amaranth Advisors, LLC[210] and Energy Transfer Partners, L.P.,[211] however, the Commission concluded that similar trading strategies that sought to drive down prices—which would be uneconomic when considered on a stand-alone basis, but would generate countervailing profits for other trading positions in the portfolio—constitute market manipulation. Moreover, as recently as one day ago, the Commission recognized the ability and incentive of such "buyers' cartels" to profitably suppress

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[208] Hogan Policy Paper at 14 (emphasis added). *See also* Comments of Robert L. Borlick Energy Consultant at 11, Docket No. RM10-17-000 (filed May 13, 2010) ("Borlick Comments") ("[f]or a regulator to employ demand response for the explicit purpose of driving down market prices to benefit consumers is tantamount to enforcing the exercise of monopsonistic market power.").

[209] *See* NEPGA Reply Comments at 2.

[210] 120 FERC ¶ 61,085 (2007).

[211] 120 FERC ¶ 61,086 (2007)).

prices through subsidized, uneconomic entry, and reaffirmed its long-standing policy of prohibiting such conduct.[212] The Final Rule thus not only completely ignores regulated sellers' rights to just and reasonable compensation and the Commission's "statutor[y] mandate[]"[213] to prevent the exercise of buyer market power to artificially suppress prices, but it appears to embrace conduct that would be considered market manipulation if undertaken by market participants. "Buyers' cartels" will now have free rein to exercise market power to suppress prices below competitive, or even compensatory, levels, and thereby transfer revenues from jurisdictional sellers to non-jurisdictional DR providers and other buyers.

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[212] Specifically, the Commission stated:

> Entities with buyer-side market power can artificially lower the capacity price, sometimes substantially, by subsidizing new investment that is then offered into the market at prices below its full entry costs. . . The cost of the subsidized new resource is higher than the market price, which on first impression would seem to be financially harmful to buyers. But buyers as a whole may benefit from the subsidized resource because the lower market price may reduce the total bill for acquiring existing capacity, and this bill reduction may outweigh the net cost of the new resource.

ISO New England Inc. & New England Power Pool Participants Comm., 135 FERC ¶ 61,029 at P 158 (2011).

[213] *PJM*, 135 FERC ¶ 61,022 at P 143.

6. The Perceived Need For A Net Benefits Test Highlights The Fact That The Final Rule Is Not The Product Of Reasoned Decisionmaking.

The addition of a cost-effectiveness condition—the "net benefits" test—exacerbates the inefficiencies caused by paying DR LMP, and creates additional (and perhaps insurmountable) implementation problems. For these and other reasons, all of the ISOs/RTOs uniformly opposed the Commission's proposal to adopt a net benefits test,[214] along with a clear majority of commenters from across the spectrum.[215] As the Midwest ISO explained, "[s]uch a test is both unnecessary in a competitive wholesale market and the ***very antithesis*** of one," and would "distort the decision of

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[214] As Commissioner Moeller noted at the March 17, 2011 meeting, all of the ISOs/RTOs said "please, please, please don't give us a net benefits test, because we don't know how to do it. Yet that's what the rule did." March 17, 2011 Commission Meeting Tr. at 13:10-12. *See also* Comments of the California Independent System Operator Corporation at 4-5, Docket No. RM10-17-000 (filed Oct. 13, 2010); Comments of ISO New England Inc. at 4-6, Docket No. RM10-17-000 (filed Oct. 13, 2010); Midwest ISO Post-Conference Comments at 9-10; Comments of the New York Independent System Operator, Inc. at 3-4, Docket No. RM10-17-000 (filed Oct. 13, 2010); Comments of Southwest Power Pool, Inc. at 3-4, Docket No. RM10-17-000 (filed Oct. 13, 2010); Statement of Andrew L. Ott at 2-4, Docket No. RM10-17-000 (dated Sept. 13, 2010).

[215] Moeller Dissent at 6. *See also* Final Rule, FERC Stats. & Regs. ¶ 31,322 at P 40 (noting that "[o]pposition to use of a net benefits tests comes from several directions.").

when to procure DR."[216] Moreover, the net benefits test further distorts market prices over and above the inefficiencies due to overcompensating DR,[217] and it may discourage market participants from hedging.[218] Further, the test presents potentially insoluble computational and implementation issues.[219]

(a) The Net Benefits Test Facilitates The Exercise Of Buyer Market Power.

The net benefits test facilitates, or even mandates, the exercise of buyer market power to transfer wealth from sellers to buyers,[220] and, as noted above, essentially has the Commission acting to enforce a "buyers' cartel" by ensuring that DR is paid full LMP only when it will serve the collective interests of buyers as a

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[216] Midwest ISO Post-Conference Comments at 9 (emphasis added).

[217] *See, e.g.*, FTC Comments at 5 ("[a] plan to inflate the formula for demand response payments to offset insufficient LMPs is very likely to miss the efficient result and instead produce a hodgepodge of over- and under-compensation for demand response.").

[218] *See, e.g.*, Ott Statement at 8 (explaining that the net benefits test would "create perverse incentives" because customers who have hedged may still be allocated costs, which may encourage them to discontinue hedging practices.).

[219] *See id.* at 2 (asserting that it would be nearly impossible to identify specific beneficiaries in practice because (1) "it is not practical to rerun market results with and without" DR "to accurately identify specific beneficiaries for specific hours;" and (2) customers "may not directly benefit from reduced prices because they may already be hedged. . . . ").

[220] *See* Hogan Policy Paper at 14; Borlick Comments at 10-11.

class. As NEPGA explained, the net benefits test would require an ISO or RTO to pay DR LMP based on its determination as to whether dispatching the DR resource is cost-effective by taking into account the "portfolio benefits" for other buyers, rather than whether it would be cost-effective on a stand-alone basis.[221] In this regard, the Commission appears to be following a troubling approach adopted by several States in recent years in the form of "Demand Reduction-Induced Price Effect," or "DRIPE." DRIPE specifically excludes savings from the avoided costs of foregone retail purchases, and refers only to the reductions in energy and capacity prices through the exercise of buyer-side market power, *e.g.*, by subsidizing DR.[222] "DRIPE programs are based on the premise that subsidies for demand response can pay

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[221] *See* NEPGA Reply Comments at 2. These concerns were echoed by Roy J. Shanker, Ph.D., who commented on the troubling way in which the NOPR contemplated the "consideration of portfolio effects caused by the reduced demand on all load payments, versus the economic decision-making of individual market participants pursuing their own legitimate business purposes." Tech Conf. Tr. at 61:17-21.

[222] Post-Conference Comments of the New England Power Generators Association, Inc. at 5, Docket No. RM10-17-000 (filed Oct. 13, 2010) (internal citations omitted) ("NEPGA Post-Conference Comments"). In fact, as NEPGA's representative, Mr. Joel Newton of NextEra Energy testified at the Technical Conference, DRIPE and similar programs are "the mirror image of a generator withholding." Tech. Conf. Tr. at 28:16-17.

for themselves—***and more***—by depressing energy and capacity prices for all market purchases."[223]

In the Final Rule, the Commission barely responded to legitimate concerns that the Commission was pursuing a similar strategy, brushing them aside with the bald assertion that "[i]mposing a cost-effectiveness condition does not convert this unit commitment process by the RTO or ISO into collusion among bidders."[224] A simple denial, without providing a reasoned analysis demonstrating why commenters concerns are unfounded, does not even begin to satisfy

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[223] NEPGA Post-Conference Comments at 1 (emphasis in original). NEPGA set forth the disturbing parallels between the Commission's approach and DRIPE as follows:

> Both seek to determine whether demand response resources ought to be created for the capacity markets or dispatched in the energy markets. Both go beyond competitive considerations of whether a particular marginal unit of demand response would be the most economic source of capacity or power. Both look to the price effect of using demand response and attempt to justify its use on a portfolio basis, even if any individual unit might not be economic. Both are open and flagrant invitations to the use of buyer market power. Both should be rejected as unlawful and contrary to the Commission's commitment to competitive markets.

Id. at 5-6.

[224] Final Rule, FERC Stats. & Regs. ¶ 31,322 at P 65. *See also id.* (stating that the Commission "disagrees that market rules establishing circumstances in which particular resources can participate and receive the LMP represents cooperative price setting").

the Commission's obligation to engage in reasoned decisionmaking.[225]

Moreover, the Commission's decision to adopt the "net benefits" test was not supported by reasoned decisionmaking, because the Commission explicitly acknowledged that its "net benefits" approach cannot achieve the purpose for which it was adopted (*i.e.*, identifying hours in which it is cost-effective to pay DR the full LMP and in which the cost savings from reduced LMPs will offset the "billing unit effect").[226] According to the Commission:

> the threshold price approach we adopt here may result in instances both when demand response not paid the LMP but would be cost-effective and when demand response is paid the LMP but is not cost-effective.[227]

The Commission went on to acknowledge that there will inevitably be differences among the tests that ISOs/RTOs ultimately adopt, and that these differences will cause DR to receive differing levels of compensation in each ISO/RTO.[228] The Commission of-

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[225] *See, e.g., PPL Wallingford*, 419 F.3d at 1198.

[226] *See MoPSC II*, 337 F.3d at 1075 ("[r]eliance on facts that an agency knows are false at the time it relies on them is the essence of arbitrary and capricious decisionmaking.").

[227] Final Rule, FERC Stats. & Regs. ¶ 31,322 at P 80.

[228] *See id.* at P 78 n.160 ("[t]here will be inherent differences in the supply curves determined by each RTO and ISO under the net benefits test required herein due to decisions the RTOs and ISOs

fered no explanation as to why it will permit variations among ISOs/RTOs in DR compensation stemming from the methodology chosen for the net benefits test, but not for other reasons.

(b) Costs Of DR Compensation Should Be Allocated Based On Net Purchases, And Should Not Be Allocated To Self Supply.

The Final Rule requires that the costs of the DR subsidy, i.e., the costs of paying full LMP to DR resources, be allocated "to all entities that purchase from the relevant energy market in the area(s) where the demand response reduces the market price for energy at the time when the demand response resource is committed or dispatched."[229] The Competitive Supplier Associations interpret the Final Rule as meaning that costs associated with DR compensation should be allocated to net purchasers (*i.e.*, market participants whose net cleared demand exceeds their net cleared supply) on the basis of net purchases in the ISO/RTO energy markets, and respectfully request clarification to that effect. In the alternative, if the Final Rule would allow costs to be allocated to market participants to the extent they are self supplying energy (*i.e.*, the extent to which their cleared supply offsets their

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must make based on supply data for their regions, the mathematical methods each RTO and ISO chooses to use for smoothing the supply curves, the certainty of changes in supply due to outages in each region, local generation heat rates, and the choice of relevant fuel price indices.").

[229] *Id.* at P 102.

cleared demand), the Competitive Supplier Associations respectfully request rehearing.

The stated purpose of allocating DR compensation costs on the basis prescribed by the Final Rule is to "allocate the costs of demand response to those who benefit from the lower prices produced by dispatching demand response."[230] Leaving aside for the moment questions of whether customers truly benefit in the long term from price suppression of the sort contemplated by the Final Rule (and they do not),[231] it should be indisputable that market participants do not benefit, even in the short run, from lower LMPs resulting from dispatching DR with respect to their self supplied energy needs.[232] Allocating costs associated with DR dispatch to self supplied energy would be inconsistent —and, indeed, fundamentally at odds—with the stated intent of the cost allocation methodology prescribed in the Final Rule. As a result, such an approach would clearly be arbitrary and capricious.[233] Moreover, it

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[230] *Id.* at P 100.

[231] *See supra* Section III.B.2.

[232] In general, in any hour of the day ahead or real time energy market, a market participant's cleared supply offers are credited at the respective LMP and its cleared demand bids (or, in real time, its load) are charged at the respective LMP with the market participant receiving only the net credits after meeting own energy obligations. Because DR-induced LMP reductions would decrease both the charges and credits for energy, no benefit would be received for the amount by which the market participant's credits offset its charges in that hour.

[233] *See, e.g., State Farm*, 463 U.S. at 43.

would be contrary to the law, inasmuch as it would conflict with the very decisions cited in the Final Rule for the proposition that the Commission's allocation rule was "consistent with long-standing judicially-endorsed cost allocation principles,"[234] and other decisions holding that "all approved rates [must] reflect to some degree the costs actually caused by the customer who must pay them."[235]

Allocating the costs of DR compensation to self supply would not only unfairly and unjustifiably impact market participants electing to self supply (including generators self supplying station power requirements), but would also undermine the operation of the net benefits test. The stated purpose of the net benefits test is to ensure that DR is "cost-effective," in the sense that it is being dispatched when "the nature of the supply curve is such that small decreases in generation being called to serve load will result in price decreases sufficient to offset the billing unit effect."[236] Understating the billing unit effect by allocating costs to self supply—which does not benefit from the price decreases—will cause the net benefits test to produce

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[234] *See* Final Rule, FERC Stats. & Regs. ¶ 31,322 at n.195 (*citing Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1368, 1370-71 (D.C. Cir. 2004)); *ICC*, 576 F.3d at 476.

[235] *KN Energy*, 968 F.2d at 1300. *See also Pacific Gas & Elec. Co. v. FERC*, 373 F.3d 1315, 1320-21 (D.C. Cir. 2004); *Transmission Access Policy Study Group v. FERC*, 225 F.3d 667, 708 (D.C. Cir. 2000).

[236] Final Rule, FERC Stats. & Regs. ¶ 31,322 at P 80.

"false positives" and thus payment of full LMP to DR when, even by the terms of the Final Rule, there are no net benefits from dispatching DR. In this respect, the allocation of costs of DR compensation to self supply would be arbitrary and capricious.[237]

7. The Commission's Determination To Adopt The Final Rule In The Absence Of Measurement And Verification Standards Capable Of Preventing Manipulation Is Arbitrary And Capricious.

The Commission agreed with commenters that "measurement and verification are critical to the integrity and success of demand response programs," because in the absence of such standards, ISOs/RTOs "cannot determine whether that provider has in fact reduced its energy usage when paid to do so."[238] Yet the Final Rule creates significant, and perhaps insurmountable, difficulties for ISOs/RTOs in measuring customers' demand reductions and verifying that they have reduced consumption ***in response to price signals***,

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[237] *See, e.g.*, *State Farm*, 463 U.S. at 43.

[238] Final Rule, FERC Stats. & Regs. ¶ 31,322 at P 93. *See also* ISO-NE Comments at 4; Comments of Joint Consumer Advocates at 12, Docket No. RM10-17-000 (filed May 13, 2010). The Commission directed ISOs/RTOs to review their current standards, and, in their compliance filing to make any changes to those standards necessary "to ensure that their baselines remain accurate and that they can verify that demand response resources have performed." Final Rule, FERC Stats. & Regs. ¶ 31,322 at P 94.

rather than for other reasons such as day-to-day variations in temperature or demand.[239]

Like the net benefits test, however, current measurement and verification standards are simply not capable of performing the functions they are intended to serve, in particular, preventing manipulation. ISOs/RTOs and other commenters, including the Competitive Supplier Associations, pointed out that the current standards—the "Phase I" standards of the North American Energy Standards Board ("NAESB") —are not sufficient for ISOs/RTOs to adequately verify the amount by which DR providers have reduced consumption.[240] The Commission itself has acknowl-

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[239] The Commission's approach of paying full LMP may render it impossible, even in theory, to accurately estimate customer baselines and demand reductions in response to price signals. *See, e.g.*, ISO-NE Comments at 4 ("[t]here is no baseline estimation technique that can accurately and reliably estimate what a customer's energy usage pattern would have been if that customer responds frequently to price signals."). The Commission could have avoided these potentially intractable baseline estimation problems if it had adopted an alternative compensation method such as LMP-G, or the "buy the baseline" approach advocated by ISO-NE.

[240] *See generally Standards for Business Practices and Communication Protocols for Public Utilities*, Order No. 676-F, 131 FERC ¶ 61,022 (2010) ("Order No. 676-F"). These measures, while helpful, only serve as a framework and lack necessary detail and specificity, which is intended to be developed in NAESB's "Phase II" measurement and verification standards development process, which is now underway and expected to be completed in late 2011. Similarly, the North American Electric Reliability Council ("NERC") is in the early stages of developing measure-

edged that the Phase I NAESB standards are only a "starting place"[241] and that additional standards will be necessary for transparent and consistent measurement and verification of DR products and services.[242] Payment of full LMP in the absence of effective measurement and verification standards, however, invites manipulative strategies to fraudulently collect DR payments without actually reducing consumption, *e.g.*, by inflating baseline estimates to receive payments for normal consumption or day-to-day load variations,[243] or though "load shifting" strategies.[244]

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ment and verification standards, but these standards are a long way off, and current indications are that there will be some inconsistencies between the NERC and NAESB standards that will take additional time to work out. *See* EPSA Comments at 30-31.

[241] Order No. 676-F, 131 FERC ¶ 61,022 at P 35.

[242] *Id.* at P 32. The Commission went on to add that the "measurement and verification standards needed to accomplish this goal should be a focus of NAESB's Phase II M&V Standards development efforts." *Id.*

[243] ISO-NE Comments at 32-33. *See also id.* at 31 (explaining that baseline estimation methods available under existing standards "invite sophisticated market participants to strategically schedule load reduction events so as to manipulate the baseline calculation.").

[244] According to the American Council for an Energy-Efficient Economy:

> DR has virtually always been implemented during times (i.e., business weekdays) when customers would be engaged in "normal" business operations, greatly enhancing the likelihood that claimed load drops/shifts are "real", and not free- ridership or gaming of production scheduling. If a customer or DR aggregator is free to

Concerns about gaming and manipulation are not just theoretical, as the Commission appears to acknowledge in the Final Rule.[245] In fact, an official of the Electricity Consumers Resource Council has admitted that "compensation for curbing demand has to be significant for [manufacturers] to shift their production to another time,"[246] *i.e.*, to engage in load-shifting strategies that do not actually decrease total consumption. The official also acknowledged that "the environmental benefits of DR have been 'grossly oversold,' because it basically shifts production timing."[247] The Commission has taken enforcement action against at least one DR provider for violations of the Commission's regulations prohibiting market manipulation[248] and PJM's tariff.[249] The Commission has

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> bid on DR resources literally at any time, it is almost an open invitation to "game" the system and take advantage of internal scheduling opportunities to claim compensation for load shifts/reduction which would have occurred during an off-peak period anyway. It will be extremely difficult to verify a valid 24/7/365 "baseline" for large industrial customers, and particularly for an aggregated group of customers.

Comments of the American Council for an Energy-Efficient Economy Comments at 4, Docket No. RM10-17-000 (filed May 13, 2010).

[245] *See* Final Rule, FERC Stats. & Regs. ¶ 31,322 at P 95 (clarifying that "demand reductions that are not genuine may be violations of the Commission's anti-manipulation rules.").

[246] Energy Washington, "Power Marketers May Sue FERC Over Rule Encouraging Efficiencies" (posted Mar. 21, 2011).

[247] *Id.*

[248] 18 C.F.R. § 1c.2 (2010).

also issued public notices that Commission OE Staff has preliminarily determined that participants in ISO-NE's Day-Ahead Load Response Program ("DALRP") violated the Commission's anti-manipulation rule by artificially inflating their baseline loads and misrepresenting their load profiles to fraudulently collect DALRP payments.[250]

While it is heartening that the Commission appears to take seriously the threat of manipulation by DR providers, the Commission's decision to adopt the Final Rule, before meaningful measurement and verification standards have been developed, was arbitrary and capricious. The evidence in the record unequivocally indicates that current NAESB standards and ISO/RTO rules cannot prevent fraud and abuse. As noted above, the Commission itself has acknowledged that the current NAESB Phase I measurement and verification standards are only a "starting place,"[251]

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[249] *See North Am. Power Partners*, 133 FERC ¶ 61,089 (2010) (order approving stipulation and consent agreement between the Commission's Office of Enforcement ("OE") Staff and North America Power Partners to resolve violations of the Commission's anti-manipulation rule and PJM's tariff provisions, including a civil penalty of $500,000 and disgorgement of more than $2.25 million, plus interest, in unjust profits).

[250] *See* Staff Notice of Alleged Violations (Jan. 25, 2011) (notice of violations by Lincoln Paper and Tissue, LLC); Staff Notice of Alleged Violations (Jan. 25, 2011) (notice of violations by Competitive Energy Services, LLC); Staff Notice of Alleged Violations (Jan. 25, 2011) (notice of violations by Rumford Paper Company).

[251] Order No. 676-F, 131 FERC ¶ 61,022 at P 35.

while ISOs/RTOs and others have submitted uncontroverted evidence that, under the Commission's approach, it may not be possible, even in theory, to accurately estimate customer baselines or to identify and measure the amount of demand reductions made in response to price signals. The Commission, however, summarily dismissed these concerns, and blithely assumed that current ISO/RTO rules, as modified on compliance, will be sufficient to address any concerns.[252] The Commission's determination that ISOs/RTOs will be able to solve the problems created by the Final Rule regarding measurement and verification—where these same ISOs/RTOs have informed the Commission that they do not know how to do so and that these problems may in fact be intractable under the

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[252] *See* Final Rule, FERC Stats. & Regs. ¶ 31,322 at PP 93-94. The Commission's response to these commenters—that the adoption of the net benefits test means that LMP will not be paid to DR resources in all hours and that, consequently, the "implementation of the Final Rule would not appear to prevent the adoption of appropriate baselines," *id.* at P 94—does not address, or rebut, their concerns. The adoption of the net benefits test does not reduce or eliminate the practical difficulty of estimating the baseline and measuring the reduction in consumption for any particular hour. Moreover, it is ironic that the Commission would rely on the net benefits test—which was uniformly opposed by all ISOs and RTOs and the clear majority of speakers at the September 13, 2010 Technical Conference who argued that the test would be impractical or impossible to implement and/or could not serve its intended purpose—to "solve," at least in part, the measurement and verification problems caused by its adoption of the Final Rule.

Commission's approach—"is the essence of arbitrary and capricious decisionmaking."[253]

C. The Commission's Conclusion That A Uniform, National Rule For DR Compensation Is Necessary To Ensure That ISO/RTO Rates Are Just And Reasonable Is Arbitrary And Capricious, And Unsupported By Substantial Evidence.

1. The Commission Improperly Shifted The Burden Of Proof.

In defense of its decision to impose a uniform, national rule for DR compensation, the Commission unlawfully shifted to commenters its own burden of proof, essentially requiring commenters to demonstrate that existing, Commission-approved ISO/RTO compensation rules remain just and reasonable.[254] As noted above, the Commission's action in this regard is unlawful, because it has not even attempted to satisfy the requirements of Section 206 of the FPA. But even assuming *arguendo* that it had, the Commission's action would still be unlawful insofar as it asserts that commenters bear the burden of demonstrating that existing, Commission-approved tariff provisions should be retained, rather than acknowledging that it is the Commission that bears the burden of proof for chang-

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[253] *See MoPSC II*, 337 F.3d at 1076.

[254] *See* Final Rule, FERC Stats. & Regs. ¶ 31,322 at P 67 ("the commenters have not shown why such [regional] differences warrant a different compensation level among the ISOs and RTOs.").

ing existing tariff provisions under Section 206 of the FPA.[255]

2. The Commission's Determination Departs Without Adequate Explanation From Long-Standing Policy Permitting Regional Variations In Market Rules.

In the Final Rule, the Commission departed, without adequate explanation, from its long-standing policy beginning with Order No. 2000[256] of not only permitting, but encouraging, regional variations and experimentation in ISO/RTO rate and market design.[257] The Commission utterly failed to justify why it chose

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[255] *See* 16 U.S.C. § 824e(a) (2006); *Alabama Power*, 993 F.2d at 1571 ("the proponent of a rate change under § 206, here [the Commission], has the burden of proving that the existing rate is unlawful. . . . ").

[256] *Regional Transmission Organizations*, Order No. 2000, FERC Stats. & Regs. ¶ 31,089 (1999) ("Order No. 2000"), *order on reh'g*, Order No. 2000-A, FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom. Pub. Util. Dist. No. 1 of Snohomish County, Washington v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

[257] The Commission has not explained why it is important to require standardization solely for ISO/RTO markets, but not for other markets. As far as the Competitive Supplier Associations are aware, the Commission has not given any indication that it will require such standardization for non-ISO/RTO markets. This notable omission begs the question of whether the Commission has accepted that DR standardization outside the ISO/RTO context raises retail jurisdictional concerns, but somehow believes that a different rule obtains in the ISO/RTO markets. In any case, this aspect of the Final Rule is likewise unduly discriminatory.

DR compensation as the one element of market design to be singled out for standardization. Nor did it explain why such selective and preferential uniformity is needed to make ISO/RTO rates just and reasonable or why existing market rules, previously accepted as just and reasonable, would become unjust and unreasonable in the absence of the changes required by the Final Rule.[258] As such, its action is arbitrary and capricious.[259]

In Order No. 2000, the Commission emphasized that it was not proposing a "cookie cutter" format for RTOs, and that it would instead adopt an "open architecture" to give each RTO and its members the flexibility to adapt their market rules as necessary to meet market needs.[260] More recently, in Order No. 719, the Commission reaffirmed its policy of permitting regional variations,[261] and directed each ISO and RTO to develop its own mechanism for DR price formation and

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[258] *See, e.g.*, Moeller Dissent at 2 (noting that the Commission has not found "the existing region-by-region approach to compensation is unjust and unreasonable.").

[259] *See, e.g., Wisconsin Valley*, 236 F.3d at 748 (stating that "an agency acts arbitrarily and capriciously when it abruptly departs from a position it previously held without satisfactorily explaining its reason for doing so.").

[260] Order No. 2000, FERC Stats. & Regs. ¶ 31,089 at 31,061.

[261] Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 10 ("Absent a single national power market, the development of regional markets is the best method of facilitating competition within the power industry.").

compensation.[262] The Commission explicitly rejected the need to adopt a uniform, national rule to standardize DR products[263] and technical requirements across ISOs/RTOs.[264] In addition, the Commission declined to address the "double payment" issue for DR resources ancillary services markets, noting that the issue would be "more appropriately addressed by each region," working with stakeholders, "including state and local regulatory authorities."[265] Similarly, the Commission has affirmed regional variations for various aspects of market design in generic rulemaking proceedings and proceedings involving individual ISO/RTO market rules, *e.g.*, rules governing capacity markets, scarcity pricing, and long-term firm transmission rights.[266]

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[262] *See id.* at P 50.

[263] *See id.* (concluding that, because "[e]ach RTO and ISO is unique, ... the Commission hesitates to impose a uniform definition.").

[264] In Order No. 719, the Commission concluded that:

> It is not appropriate in this rulemaking to develop a standardized set of technical requirements for demand response resources participating in ancillary services markets. Instead, the Commission will allow each RTO and ISO, in conjunction with its stakeholders to develop its own minimum requirements.

Id. at P 59.

[265] *Id.* at P 159.

[266] *See, e.g., Midwest Indep. Transmission Sys. Operator, Inc.*, 116 FERC ¶ 61,292, at P 53 (2006); *Long-Term Firm Transmission Rights in Organized Electricity Markets*, Order No. 681, FERC Stats. & Regs. ¶ 31,226, at P 100 (2006); *Southwest Power*

3. The Commission's Determination To Impose A "One Size Fits All" Rule Is Arbitrary And Capricious.

The Commission failed to establish that permitting regional differences in compensation constitutes a barrier to entry, or to explain how variations among the various ISO/RTO DR compensation rules render them unjust and unreasonable, restrict competition, or facilitate the exercise of market power.[267] As noted above, ISOs/RTOs and their market monitors were uniformly opposed to the adoption of a uniform, national rule. For example, Potomac Economics, the external or independent market monitor for ISO-NE, the Midwest ISO and the NYISO opposed standardization, because:

> [R]ecognition of differing retail rate structures may require flexibility by the Commission, rather than a one-size-fits-all approach to structuring DR settlement rules in each ISO market. Hence, we would encourage the Commission to establish guidelines for the ISOs that would be premised on

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Pool, Inc., 110 FERC ¶ 61,031 at P 22-23 (2005); *Midwest Indep. Transmission Sys. Operator, Inc.*, 102 FERC ¶ 61,196 at P 43 (2003).

[267] In this regard, there are numerous differences in the ISO/RTO rules governing compensation for generators. The Final Rule failed to note this fact, or to offer an explanation as to why it will permit such regional differences for generators, but must eliminate them for DR.

> maximizing economic efficiency, rather than requiring a specific DR payment scheme.[268]

Numerous State regulators voiced similar concerns. As the CPUC explained:

> [I]t is unclear whether the NOPR provides an adequate record from which to conclude that the proposed payment method is the only just and reasonable compensation structure across all ISOs, RTO's states, regions, and local regulatory authority zones. [P]romulgating a uniform national rule at this time may inadvertently impede the implementation of the optimal demand response compensation for an individual ISO or RTO which addresses the needs of that particular region.[269]

Commenters from other industry segments likewise opposed standardization. For example, APPA and NRECA advocated:

> allowing local and regional differences to be reflected in pricing rules in RTO-run markets. In

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[268] Potomac Economics Comments at 9-10.

[269] CPUC Comments at 5-6. *See also* Comments of the ISO/RTO Council in Response to the Federal Energy Regulatory Commission's Notice of Proposed Rulemaking on Demand Response in Organized Wholesale Markets at 2, Docket No. RM10-17-000 (filed May 13, 2010) ("urging the Commission to adopt an approach that allows "each ISO/RTO to select an approach that best fits with retail regimes in its footprint."); NYISO Comments at 16 (the Commission "should leave the details of compensation to individual ISOs/RTOs.").

> general, demand response rules in RTO-run markets have evolved to meet specific needs. Local and regional conditions largely determine what form and what compensation level for demand response is appropriate. The availability of particular resources in a particular region can mean that different compensation levels are needed to optimize the development of demand response. Varying consumer load profiles and retail market structures dictate that different compensation levels are appropriate in different RTO-run markets.[270]

Trade associations representing LSEs and generators, such as EEI and EPSA, also opposed standardization for largely the same reasons.[271]

Each ISO/RTO has a set of unique DR products for energy, capacity, and/or ancillary services. Paying the same price for different products hardly achieves the uniformity that the Commission so obviously desires. For example, according to the National Action Plan on Demand Response prepared by Commission Staff, PJM, the Midwest ISO, and the NYISO each offer seven total DR products (three of which are for energy), while ISO-NE offers nine separate DR prod-

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[270] APPA/NRECA Comments at 11-12.

[271] *See* EPSA Comments at 62-70; EEI Comments at 2 ("EEI therefore takes the position that the individual ISOs/RTOs should have the option to structure demand response compensation as their stakeholders choose to do so.").

ucts (four of which are for energy).[272] Requiring uniform compensation for these disparate products will inevitably distort market participants' incentives to purchase or sell these DR products.

The Commission erred by failing to respond to the serious objections raised by the Competitive Supplier Associations, ISOs/RTOs, State commissions and others that opposed standardization and supported the retention of the Commission's long-standing policy of permitting regional variation.[273] In addition, the Commission failed to draw a "rational connection"[274] between the problem the rule purports to solve (*i.e.*, inadequate DR participation and barriers to entry by DR) and the solution it chose (*i.e.*, a uniform, national rule on DR compensation), or to explain how increased DR compensation will solve that problem.

D. The Commission's Rejection Of The LMP-G Alternative Is Arbitrary And Capricious And Not Supported By Substantial Evidence.

Commenters from across the spectrum,[275] including ***all*** of the ISOs/RTOs with economic DR pro-

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[272] Federal Energy Regulatory Commission Staff, *National Action Plan on Demand Response*, App. B at B-12 to B-14, Docket No. AD09-10-000 (June 17, 2010).

[273] *See, e.g.*, *CAPP*, 254 F.3d at 299.

[274] *State Farm*, 463 U.S. 29, 43.

[275] *See* EPSA Reply Comments at 36-40 & n.70 (list of commenters that supported including an offset for avoided retail costs).

grams,[276] supported the payment of LMP with an offset for avoided retail costs. Notably, even the CAISO, which pays full LMP in its markets, urged the Commission to give ISOs/RTOs the flexibility to account for retail rates in their DR compensation programs.[277] These commenters supported payment of LMP-G, because it is the efficient level of compensation, and would also avoid the need for a net benefits test or a cost allocation mechanism. According to the NYISO:

> [P]aying demand response LMP minus a proxy cost for their retail rate (LMP-G) provides the correct economic signals within a wholesale market framework, avoids the need for complicated and contentious net benefits tests and cost allocation rules, and comports much more closely to the outcomes derived from dynamic retail pricing.[278]

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[276] *See* CAISO Comments at 3; ISO-NE Comments at 40-44; Midwest ISO Comments at 3; NYISO Comments at 3; PJM Comments at 6.

[277] CAISO Comments at 3 (stating that it supports the Commission's proposal, but emphasized that "other compensatory measures . . . , such as subtraction of the retail rate, or a portion thereof, [are] appropriate for consideration by the ISO or RTO, its stakeholders, and the relevant retail electric regulatory authority, rather than for standardization by the Commission.").

[278] NYISO Comments at 1. *See also* Midwest ISO Comments at 5 (supporting payment of LMP-G because it: (1) makes the LSE financially indifferent, so that it pays the same amount regardless of whether demand reductions occurred; (2) "avoids the creation of cross-subsidies among LSEs and their retail customers;" and (3)

This alternative was also supported by State regulators. For example, the Public Utilities Commission of Ohio explained the reasons for its support as follows:

> [T]he most appropriate payment for demand response resources in wholesale energy markets is LMP minus the generation portion of the retail rate. This is the economically efficient incentive for demand response resources in these markets. By reducing demand, the responding consumer is already avoiding payment for energy that was not consumed.[279]

Commenters representing generators appear to have uniformly supported the payment of LMP-G.[280]

The Commission's rejection of the LMP-G alternative proposed by commenters, and supported by Commission Moeller,[281] was arbitrary and capricious because it failed to give meaningful consideration to the

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"avoids increasing the energy 'uplift' charges that reduce market efficiency."); PJM Comments at 8-9.

[279] PUC Ohio Comments at 3.

[280] *See, e.g,* EPSA Comments at 36-40; NEPGA Comments at 4-5; P3 Comments at 3; IPPNY Comments at 3.

[281] Specifically, Commissioner Moeller stated that, while he opposed standardization of DR compensation, if he "were to now support any standardization of demand response compensation, it would be the LMP-G approach, which in my opinion, is the only economically efficient outcome for the markets." Moeller Dissent at 11.

LMP-G alternative[282] and because its rationale for rejecting this alternative is flawed. In the Final Rule, the Commission gave two reasons for rejecting the LMP-G alternative.

> First, demand response resources participating in the organized wholesale energy markets can be cost-effective, as determined by the net benefits test and, in those circumstances, it follows that the demand response resource should also receive compensation at LMP Second, such comments largely rely on arguments about economic efficiency, analogizing to incentives for individual generators to bid their marginal cost. These arguments fail to acknowledge the market imperfections caused by the existing barriers to demand response.[283]

The first reason is simply circular: it does not follow from the fact that DR "can be cost-effective" that it should therefore receive full LMP or that it should receive a subsidy equal to its avoided costs. The Commission's second reason for dismissing arguments that payment of LMP would overcompensate DR is inter-

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[282] *See, e.g., AGA*, 593 F.3d at 14 ("[w]here a dissenting Commissioner raises a reasonable alternative, the majority is required to consider it."); *Laclede Gas*, 873 F.2d at 1498 ("[w]here a party raises facially reasonable alternatives to [the Commission's] decision ... the agency must ***either*** consider those alternatives ***or*** give some reason within its broad discretion ... for declining to do so.") (emphasis in original).

[283] Final Rule, FERC Stats. & Regs. ¶ 31,322 at P 61.

nally inconsistent. As described above, the Final Rule selectively requires "comparable" treatment of DR and generation where the uniform standard is favorable to DR (*i.e.*, requiring payment of full LMP, which gives DR effectively compensates DR at LMP+G),[284] but permits disparate treatment when the double standard would work in DR's favor (*e.g.*, by permitting DR resources to participate in ISO/RTO subject to less stringent performance requirements and penalties than those at apply generators).

The other reasons cited by the Commission are similarly without merit. For example, the Commission's suggestion that it would not be appropriate to use LMP-G due to concerns about computational difficulties or conflicts with retail rate regulation[285] was without merit, as ISOs/RTOs and State commissions indicated that the retail rate can be deducted from LMP without the claimed difficulties,[286] and the Commission acknowledges that it may be "feasible" to do so.[287] In any case, the fact of the matter is that many

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[284] *See* Moeller Dissent at 4.

[285] Final Rule, FERC Stats. & Regs. ¶ 31,322 at PP 28, 63.

[286] In fact, none of the ISOs/RTOs claimed that there would be any difficulty in subtracting the retail rate from LMP. *See* CAISO Comments at 5-6; ISO-NE Comments at 17-26; Midwest ISO Comments at 6-11; NYISO Comments at 12-16; PJM Comments at 5-16.

[287] Final Rule, FERC Stats. & Regs. ¶ 31,322 at P 63.

of the ISOs/RTOs already deduct retail rates from LMP.[288]

E. The Commission's Determination Was Contrary To Law And Arbitrary And Capricious Because It Violated The Requirements Of The RFA.

The Final Rule violates the requirements of the RFA,[289] which requires the Commission to include in the Final Rule a description and analysis[290] of rules that will have a significant economic impact on a substantial number of small entities.[291] Specifically, the

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[288] As noted above, the Midwest ISO and PJM already deduct the retail rate from LMP.

[289] 5 U.S.C. §§ 601-612 (2006).

[290] The RFA further requires the Commission, when it promulgates a final rule, to issue a description of the compliance requirements for the rule and an analysis that, among other things, estimates the impact of the rule on small businesses and describes the steps that the Commission took to minimize the rule's impact on small businesses, including an explanation of why any "significant alternatives" to the rule were rejected. 5 U.S.C. § 604(a) (2006). The Commission may avoid these requirements only if it certifies that the final rule "will not, if promulgated, have a significant impact on a substantial number of" small businesses, 5 U.S.C. § 605(b) (2006), which appears to be the course adopted by the Commission in the Final Rule. *See* Final Rule, FERC Stats. & Regs. ¶ 31,322 at PP 122, 129.

[291] The Small Business Administration defines a small electric utility as one that, together with its affiliates, did not generate more than four million MWh during the previous twelve months. Final Rule, FERC Stats. & Regs. ¶ 31,322 at P 122.

Administrative Procedure Act ("APA")[292] in combination with the RFA, requires the Commission analysis of its "rule's impact on small businesses be reasonable and reasonably explained," because "[a] regulatory flexibility analysis is, for APA purposes, part of an agency's explanation for its rule."[293] Thus, in assessing the costs and burdens of its proposed rule, and in weighing those costs against any anticipated benefits, the Commission must act rationally.[294] In the Final Rule, the Commission failed to satisfy its obligation to engage in reasoned decisionmaking because it simply assumed, without providing any analysis or explanation supporting its conclusion, that the Final Rule would affect only ISOs/RTOs, but not small entities.[295] In doing so, the Commission ignored the substantial number of small entities that will be significantly impacted by the Final Rule, in particular, small generators and marketers (including the Competitive Supplier Associations' members), that participate in ISO/RTO-administered markets, not to mention LSEs and DR providers whose power sales are zero or *de minimis*. As discussed in detail above, however, the Final

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[292] 5 U.S.C. §§ 551, *et seq.* (2006).

[293] *Nat'l Tel. Coop. Ass'n v. FCC*, 663 F.3d 536, 540 (D.C. Cir. 2009); *see also* 5 U.S.C. § 611(b) (in an action for judicial review of a rule, the agency's RFA analysis is part of the record in connection with such review); *Small Refiner Lead Phase-Down Task Force v. EPA*, 705 F.2d 506, 539 (D.C. Cir. 1983).

[294] *Thompson*, 741 F.2d at 405.

[295] Final Rule, FERC Stats. & Regs. ¶ 31,322 at P 122.

Rule will impose significant costs on these small entities. The Commission's failure to consider the impact of the Final Rule on these entities was therefore arbitrary and capricious.

IV. CONCLUSION

WHEREFORE, for the foregoing reasons, the Competitive Supplier Associations respectfully request that the Commission grant rehearing of the Final Rule.

Respectfully submitted,

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Dated: Apr. 14, 2011

UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. EL08-12-___

PJM INDUSTRIAL CUSTOMER COALITION

v.

PJM INTERCONNECTION, L.L.C.

Aug. 26, 2009

SUPPLEMENTAL REPORT AND SUBMITTAL OF PJM INTERCONNECTION, L.L.C. IN SUPPORT OF FURTHER COMMISSION ACTION ON REHEARING

I. INTRODUCTION

On December 31, 2007, the Federal Energy Regulatory Commission ("Commission" or "FERC") issued an order denying the complaint of the PJM Industrial Customer Coalition ("PJMICC") asking that the Commission (i) block the sunset of incentive payments under PJM Interconnection, L.L.C.'s ("PJM") Economic Load Response Program ("Economic Program") and (ii) approve the PJMICC's alternative proposal for continuing incen-

tive payments.[1] While finding, based on the record presented, that there was insufficient evidence to require PJM to continue the incentive payments, the Commission recognized that "properly tailored demand response incentives may produce just and reasonable rates" and "encourage[d] PJM and the parties to continue discussions to reach agreement on an efficient demand response program."[2] The Commission further emphasized that it would "look to PJM and its senior staff's participation to identify, analyze, and resolve remaining issues on the Economic Program."[3]

Following the *Complaint Order*, as the Commission instructed, PJM initiated a stakeholder process to address various issues regarding demand response, including market integrity of demand response, barriers to demand response, and the wholesaleretail interface for demand response. During this stakeholder process, several proposals, including a compromise proposal by PJM staff described below, were put forth and considered. This process was productive, as it narrowed the range of proposals that the stakeholders found acceptable, albeit the stakeholders were unable to reach the required consensus to enable PJM to amend the Eco-

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[1] *PJM Industrial Customer Coalition v. PJM Interconnection, L.L.C.*, 121 FERC ¶ 61,315 (2007) ("*Complaint Order*").

[2] *Complaint Order* at P 29.

[3] *Id.*

nomic Program pursuant to section 205 of the Federal Power Act ("FPA").[4]

Much has changed since the *Complaint Order*. Unlike stakeholder processes preceding the *Complaint Order*, the stakeholders were somewhat less sharply divided on many issues. The PJMICC proposal originally presented in this docket was neither formally proposed nor considered, as it did not have stakeholder support (evidenced by the Members Committee allowing the incentive to expire at the end of 2007). In contrast, and with considerable stakeholder input, PJM suggested a new, comprehensive and integrated compromise designed to improve demand response in the energy market that stakeholders in many respects were able to begin to support. While, as a whole, PJM'ssuggested approach did not obtain a super-majority sector vote enabling PJM to amend the Economic Program pursuant to section 205 of the FPA, many aspects of the compromise that PJM presented garnered significant support from the stakeholders.

Since the Commission issued the *Complaint Order*, the PJM market monitor also has observed a decrease in settled demand reductions. In 2008, settled demand

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[4] Under the PJM Operating Agreement, a two-thirds sector-weighted vote is required for PJM to submit a section 205 filing to amend the Operating Agreement. *See* Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., Third Revised Rate Schedule FERC No. 24, §§ 8.4(c), 18.6(a) ("Operating Agreement").

reductions decreased by 35.8 percent from 2007 to 458,300 megawatt hours ("MWh") (from 714,200 MWh) and they continued to decline through March 2009.[5] The PJM market monitor opined, "[w]hile the removal of the incentive program, effective November 2007, may have reduced participation, the exact role of the elimination of the incentive program is not known because there were changes in other key factors which directly impact participation."[6] The PJM market monitor further noted other possible causes for this observed decrease, including Commission-approved revisions to the Customer Baseline Load ("CBL") calculations in June 2008, implementation of a PJM settlement review process in November 2008, and average PJM price levels below 2007 and 2008 levels between October 2008 and June 2009.[7] While pinpointing the contribution of each of these factors toward the decline in settled demand reductions is difficult,[8] participation in the Economic Program stands in sharp contrast to the number of megawatts registered in the Economic Program in the 16 months following the end

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[5] Monitoring Analytics, The Independent Market Monitor for PJM, Barriers to Demand Side Response in PJM, at 22 (July 1, 2009), *available at* http://www.monitoringanalytics.com/reports/Reports/2009/Barriers_to_Demand_Side_Response_in_PJM_20090701.pdf ("July 1, 2009 Report").

[6] *Id.*

[7] *Id.* at 23.

[8] *Id.*

of the incentive program, which remained stable or increased.[9]

Therefore, despite the lack of stakeholder supermajority consensus on any single proposal in its entirety, because of the importance of strong demand response in the PJM energy markets and the Commission's expectation that PJM would work to resolve remaining issues regarding its Economic Program, the PJM Board determined to report the results of the stakeholder process to the Commission and suggest PJM's comprehensive compromise solution as a means of resolving this proceeding on rehearing. The PJM Board determined this could provide a vehicle to enable the Commission to address deficiencies of the current program and facilitate the move toward an ultimate goal of more extensive price responsive demand at the retail level,[10] rather than relying on a separate wholesale demand response program. Because PJM's suggested approach would further facilitate improved demand-side participation in the PJM energy markets, the Commission should reconsider its

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[9] *Id.* at 24. This trend also stands in contrast to the recent strong increases in demand response in the capacity market, as shown by the PJM market monitor. *Id.* at 26.

[10] Price responsive demand is when end-use customers have the metering capability to record electricity consumption at an interval of one hour or less together with a retail rate structure that changes retail rates on a daily or hourly basis in response to locational marginal prices ("LMPs") or other conditions in the PJM Interchange Energy Market.

denial of relief in this docket and adopt PJM's compromise solution.

The PJM Board believes that price responsive demand, "which allows more customers to respond directly to market prices and to voluntarily reduce their consumption when wholesale prices rise, is the ultimate solution to demand participation."[11] During the transition to price responsive demand, however, improving demand response participation in the energy markets remains crucial, as it is a valuable component of well-functioning markets.[12] Therefore, to facilitate the transition to price responsive demand and because PJM "is committed to establishing demand response as a strong participant in its energy markets,"[13] the PJM Board determined to provide the Commission a comprehensive approach to demand response for its consideration on rehearing in this docket. The comprehensive proposal is intended to: (i) emulate the financial incentives and con-

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[11] Statement of Terry Boston, President and CEO, on behalf of the PJM Board of Managers, at 1 (June 26, 2009) ("Boston Statement"), available at http://www.pjm.com/~/media/about-pjm/newsroom/2009-releases/20090626-pjmboard-statement-regarding-dr-in-pjm-markets.ashx.

[12] *See Midwest Indep. Transmission Sys. Operator, Inc.*, 108 FERC ¶ 61,163, at P 376, *order on reh'g*, 109 FERC ¶ 61,157, at P 296 (2004) ("Demand response is a critical element of an efficient electric market. As demand response increases, wholesale electric markets become more reliable and wholesale prices become less volatile.").

[13] Boston Statement at 2.

sequences of demand response actions that exist under price responsive demand; and (ii) facilitate end-users' capabilities to participate in demand response in as seamless a manner as possible.

The compromise includes three important changes to the current Economic Program, which would create a well-balanced program that will strengthen demand response in the current market environment as well as facilitate the ultimate goal of price responsive demand. First, Fixed Price Customers[14] will be compensated for their demand response at LMP less only the generation portion of their retail rates, rather than reducing demand response payments by both the generation and transmission portions of retail rates. As explained below, this change will (i) alleviate underpayment to the Fixed Price Customer, (ii) result in similar compensation for Fixed Price Customers and LMP-based Customers[15] that reduce demand, and (iii) provide Fixed Price Customers the same incentives as LMP-based Customers to reduce demand because they will receive, like LMP-based Customers, the full market value of their demand response.

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[14] A Fixed Price Customer is an end-use customer that has applicable generation charges payable to its load serving entity ("LSE") that do not change on a daily or hourly basis in direct relation to LMPs in the Day-ahead or Real-time Energy Markets.

[15] LMP-based Customers are end-use customers that have retail rates based on either Day-ahead Energy Market or the Real-time Energy Market locational marginal prices.

Second, a participant that self-schedules demand reductions or is dispatched for reductions in the Real-time Energy Market would be subject to debit payments when settlement of its daily activity shows that the participant's credits accumulated for reducing demand are less than accumulated debits for failure to reduce. Fixed Price Customers also would be subject to debit payments for reductions that are self-scheduled if the applicable zonal LMP drops below the applicable generation charge in the customer's retail rate.

Third, PJM proposes to re-introduce incentive payments for demand response. The incentives are designed to further establish demand response as a strong participant in the energy markets while the market matures to one that has more robust price responsive demand at the retail level. Under the proposal, incentive payments would be provided to customers that reduce consumption in the nine percent of hours when LMP is at its highest levels. The incentives would not be a permanent feature, but rather would sunset when there is additional price responsive demand capability (1000 new megawatts) for small and medium-sized end-use customers[16] in the PJM footprint, thus indicating that price

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[16] The 1000 MW threshold for small and medium-sized end-use customers is based on 1000 MW of peak load from customers with individual peak loads of 200 kW (0.2 MW) or less. This definition of small and medium-sized customers is consistent with the definition used in the Commission's Staff Report, A National Assessment of Demand Response Potential, at 21 (2009) ("Staff Report"),

responsive demand is playing an important role in the market and the incentives are no longer needed.[17]

PJM's suggested approach would further facilitate improved demand-side participation in the PJM energy markets. PJM therefore is reporting the results of its stakeholder process, explaining the compromise that PJM presented in that process, and requesting that the Commission reconsider its denial of relief in this docket and adopt PJM's compromise solution.

II. BACKGROUND

A. Current Economic Program

In June of 2002, PJM instituted its Economic Program in the Real-time and Dayahead Energy Markets on a temporary basis. In 2006, the Economic Program became permanent.[18] Under the current Economic Program, PJM compensates participants that voluntarily choose to reduce load during periods of high wholesale prices and scarcity. Specifically, the Economic Program provides a mechanism by which qualified LSEs or Curtailment Service Providers ("CSPs") may offer end-use customers the opportunity to commit to a reduction of load in real-time or in advance of operations and receive payments based on the real-time or

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available at http://www.ferc.gov/legal/staff-reports/06-09-demand-response.pdf

[17] The PJM Board also has directed management to produce a public report at the end of three years analyzing progress toward price responsive demand and the progress of the revised Economic Program. Boston Statement at 2.

[18] *PJM Interconnection, L.L.C.*, 114 FERC ¶ 61,201 (2006).

day-ahead LMP. Under the current Economic Program, Fixed Price Customers that reduce consumption either in the Real-time Energy Market or the Day-ahead Energy Market receive LMP less both avoided generation and transmission charges.[19] Real-time LMP-based Customers participating in the Real-time Energy Market[20] that reduce consumption receive the difference between the actual savings achieved based on zonal LMPs and the total value of the end-use customer's demand reduction bid. The total value of the demand reduction bid is the sum of the offer price (at which the end-use customer indicates it will reduce load) multiplied by the MW of reduction achieved during each hour of the time period PJM dispatched the demand reduction or the minimum down-time (whichever is greater), plus submitted start-up and opportunity costs.[21]

In the current Economic Program, a participant in the Real-time Energy Market accumulates credits for energy reductions in those hours when the energy delivered to the end-use customer is less than the end-use customer's CBL.[22] In the event the end-use customer's hourly energy consumption is greater than its

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[19] *See* Operating Agreement, Schedule 1 §§ 3.3A.4(b), 3.3A.5(b); *see also Complaint Order* at P 2.

[20] Economic Program participants that have real-time LMP-based contracts may not participate in the Day-ahead Energy Market. Operating Agreement, Schedule 1 § 3.3A.5(d).

[21] Operating Agreement, Schedule 1 § 3.3A.4(d).

[22] CBL represents end-use customers' actual load patterns and is calculated pursuant to sections 3.3A.2 and 3.3A.2.01 of Schedule 1 of the Operating Agreement.

CBL, the participant accumulates debits for the amount that the end-use customer's hourly energy consumption is greater than its CBL. However, the participant's credit can never be reduced below zero on a daily basis.[23] In contrast, in the Day-ahead Energy Market, Economic Program participants "that have demand reductions committed [and] that deviate from the day-ahead schedule in real time shall be charged or credited for such variance at the real time LMP plus or minus an amount equal to the applicable balancing operating reserve charge."[24]

» Stakeholder Process

Soon after the Commission issued the *Complaint Order*, in February of 2008, PJM convened the Demand Response Steering Committee ("DRSC") to address issues related to demand response, including market integrity, barriers to participation, and the interface between wholesale and retail electricity markets.[25] Stakeholder discussions focused on questions of compensation for demand response and measuring demand response from a participant's consumption baseline load.[26] Early in the stakeholder process, the indus-

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[23] Operating Agreement, Schedule 1 § 3.3A.4(c).

[24] *Id.* § 3.3A.5(c).

[25] *See* DRSC Meeting Agenda: PJM Interconnection Demand Side Response Policy Discussion and Scoping (Feb. 22, 2008), *available at* http://www.pjm.com/committees-and-groups/committees/~/media/committeesgroups/committees/drsc/20080222-agenda.ashx.

[26] Andrew Ott, Overview of Policy Priority: PJM Suggested Options, at 3 (Feb. 22, 2008), *available at* http://www.pjm.com/

trial customer stakeholders proposed that the DRSC consider an interim incentive for the summer of 2008,[27] but this proposal was not adopted.

At the May 9, 2008 DRSC meeting, the PJM market monitor's White Paper on PJM's Demand Side Response Program was presented,[28] which argued that while an incentive program including full LMP payment is not optimal, "payments to customers who reduce load should be based on LMP less the generation component of retail ratesbecause this reflects the

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committees-and-groups/committees/~/media/commitees-groups/committees/drsc/20080222-overview-of-policypriority-pjm-suggested-options.ashx. *See, e.g.*, Demand Response Mechanics (Mar. 13, 2008), available at http://www.pjm.com/committees-and-groups/committees/~/media/committees-groups/committees/drsc/20080313-item-05-drmechanics. ashx. *See also* Review of Revenue Opportunities for Demand Response in PJM (Mar. 13, 2008), *available at* http://www.pjm.com/committeesandgroups/committees/~/media/commitees-groups/committees/drsc/20080313-item-04-review-revenue-ops-for-demand.ashx.

[27] Consideration of an "Interim" DSR Incentive (Apr. 4, 2008), *available at* http://www.pjm.com/committees-and-groups/committees/~/media/committeesgroups/commitees/drsc/20080404-item-04-interim-incentive.ashx. The form of the incentive was not defined in this proposal.

[28] *See* DRSC Meeting Agenda (May 9, 2008), *available at* http://www.pjm.com/committees-and-groups/committees/~/media/committeesgroups/committes/drsc/2008509-agenda.ashx; *see also* MMU White Paper: PJM Demand Side Response Program (Dec. 4, 2007) ("MMU White Paper"), *available at* http://www.pjm.com/committees-and-groups/committees/~/media/committees-groups/committees/drsc/20080509-item-01-whitepaper.ashx.

resource savings associated with reducing consumption by a MWh."[29] At the same meeting, a group of electric distribution companies ("EDCs"), LSEs, and generation owners (collectively, "EDC Group") submitted a compensation proposal that continued offering LMP less generation and transmission (LMP-G&T) for demand reductions and added a minimum LMP threshold for compensating demand reductions.[30]

Beginning with the May 9, 2008 DRSC meeting and continuing through the July 9, 2008 DRSC meeting, the EDC Group and the industrial customers exchanged counterproposals and comments on those counterproposals, a process that led to the establishment of the Compensation Sub-Group consisting of industrial customers and members of the EDC Group and facilitated by PJM staff. The Compensation Sub-Group convened weekly conference calls with the aim of developing a compromise compensation proposal that would garner greater support across the PJM membership.[31] At the July 29, 2008 DRSC meeting,

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[29] MMU White Paper at 7.

[30] *See* Economic DSR Compensation (May 9, 2008), *available at* http://www.pjm.com/committees-and-groups/committees/~/media/commiteesgroups/committees/drsc/20080509-item-02-economic-dsr-compensation_.ashx.

[31] See Draft Notes from the July 29, 2008 DRSC Meeting, at 4, available at http://www.pjm.com/committees-and-groups/committees/~/media/committeesgroups/committees/drsc/20080905-20080729-draft-notes.ashx.

the Compensation Sub-Group introduced its initial compromise proposal, which adopted the industrial customers' proposed base compensation method, identical to the compensation recommended by the PJM market monitor, of LMP less the generation component of retail rates (LMP-G).[32]

The Compensation Sub-Group presented a revised compromise proposal in September 2008, which incorporated the settlement and performance metrics advocated by the industrial customers and the LMP threshold provisions for paying LMP without offset advocated by the EDC Group.[33] Discussions within the Compensation Sub-Group and at DRSC meetings continued through the end of October without reaching a consensus. At the end of October, PJM concluded that, in spite of the substantial progress and compromise to date, a comprehensive compromise agreeable to all parties was not achievable, and the members of the Compensation Sub-Group requested that PJM

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[32] *See* PJM Economic DR Program Compensation (July 25, 2008), *available at* http://www.pjm.com/committees-and-groups/committees/~/media/committeesgroups/committees/drsc/20080729-item-02-dsr-compensation-proposal.ashx.

[33] PJM Economic DR Program Compensation (Proposal July 25, 2008, Revised Sept. 4, 2008), *available at* http://www.pjm.com/committees-andgroups/committees/~/media/committees-groups/committees/drsc/20080905-item-04-compensation-draft.ashx.

develop a proposal from the results of the sub-group's efforts.[34]

In response to the issuance of Order No. 719,[35] PJM established a FERC Order 719 Task Force ("Task Force 719"), designed to facilitate stakeholder input regarding PJM's compliance obligations under Order No. 719. Because Order No. 719 addressed demand response related issues, PJM transferred certain demand response issues from the DRSC to Task Force 719. As a result, PJM presented its demand response straw proposal ("PJM Straw Proposal") at Task Force 719's initial meeting in December of 2008.[36] The PJM Straw Proposal retained most of the settlement and notification provisions for self-scheduled and real-time dispatched demand response of the final Compensation Sub-Group compromise proposal, as well as base com-

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[34] Draft Minutes from the October 31, 2008 DRSC meeting, at 5 (Dec. 3, 2008), *available at* http://www.pjm.com/committees-and-groups/task-forces/~/media/committees-groups/task-forces/tf719/20081203-item-01-minutes-20081031.ashx.

[35] Wholesale Competition in Regions with Organized Electric Markets, Order No.719, III FERC Stats. & Regs., Regs. Preambles ¶ 31,281, as amended, 126 FERC¶ 61,261, order on reh'g, Order No. 719-A, 128 FERC ¶ 61,059 (2009) ("OrderNo. 719").

[36] PJM Straw Proposal for Compensation Paid to Demand Resources Providing Demand Reductions in the Economic Load Response Program (Nov. 25, 2008), available at http://www.pjm.com/committees-and-groups/task-forces/~/media/committees-groups/task-forces/tf719/20081203-item-02b-pjm-straw-proposal-forcompensation.ashx.

pensation for demand response at LMP less the generation component of retail rates (LMP-G).[37]

At the December 19, 2008 Task Force 719 meeting, certain stakeholders commented on the PJM Straw Proposal and offered alternative proposals. The industrial customers presented a proposal based on the PJM Straw Proposal, but with modifications.[38] Public Service Electric and Gas Company ("PSEG") and Exelon Corporation ("Exelon") jointly provided a proposal also based on the PJM Straw Proposal; however, PSEG and Exelon's proposal varied from the PJM Straw Proposal in numerous ways.[39] The proposals differed along three major issues: (i) customers eligible to receive incentive payments; (ii) the threshold above which incentive payments would be made; and (iii) the duration that incentive payments

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[37] PJM Straw Proposal for Compensation Paid to Demand Resources Providing Demand Reductions in the Economic Load Response Program (Draft Nov. 25, 2008, Revised Dec. 19, 2008), *available at* http://www.pjm.com/committees-andgroups/task-forces/~/media/committees-groups/task-forces/tf719/20090109-item-02-pjm-straw-proposal-for-compensation-revised.ashx.

[38] Modifications to the PJM Economic Demand Response Program Compensation Strawman (Dec. 19, 2008), available at http://www.pjm.com/committees-andgroups/task-forces/~/media/committees-groups/task-forces/tf719/20081219-item-3b-alternative-demand-side-proposal.ashx.

[39] PJM DR Compensation (Dec. 19, 2008), available at http://www.pjm.com/committees-and-groups/task-forces/~/media/committees-groups/task-forces/tf719/20081219-item-3b-pjm-dr-compensation-pseg-exelon.ashx.

would be offered. However, there was agreement in the proposals that base compensation should be at LMP-G, and there was emerging consensus regarding the need to revise settlements for self-scheduled reductions.[40] The PJM Straw Proposal and three alternative proposals[41] were put to a non-sector vote at the January 9, 2009 Task Force 719 meeting.[42] The results are shown in the table below.[43]

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[40] Characteristics of the proposal can be seen in the comparison matrix from January 9, 2009, *available at* http://www.pjm.com/committees-and-groups/task-forces/~/media/committees-groups/task-forces/tf719/20090109-item-02-proposal-matrixfinal.ashx.

[41] Although not presented formally at any stakeholder meeting, FirstEnergy Corp. ("FirstEnergy"), Pepco Holdings, Inc. ("PHI") and Allegheny Energy, Inc. ("Allegheny") submitted for vote a proposal based on the PJM Straw Proposal, with modifications similar to those proposed by PSEG and Exelon. The aspects of this proposal can be seen in the comparison matrix from January 9, 2009, *available at* http://www.pjm.com/committees-and-groups/task-forces/~/media/committees-groups/task-forces/tf719/20090109-item-02-proposal-matrixfinal.ashx.

[42] A matrix illustrating the differences among the proposals as to certain facets of the proposals was provided to the stakeholders.

[43] *See* Draft Minutes from the January 9, 2009 Task Force 719 meeting (Feb. 2, 2009), *available at* http://www.pjm.com/committees-and-groups/task-forces/~/media/committees-groups/task-forces/tf719/20090202/20090202-item-01a-draftnotes-of-1-9-09-meeting.ashx.

	Yes	No	Abstain	% Yes
PJM ICC Proposal	26	74	17	26.00%
First Energy/PHI Allegheny Proposal	71	26	19	73.20%
Exelon/PSEG Proposal	76	33	7	69.72%
PJM Straw Proposal	45	50	22	47.37%

Subsequently, all proposals, except for the PJM Straw Proposal, were presented for a sector-weighted vote at the February 25, 2009 Markets and Reliability Committee meeting. However, none of the proposals obtained a majority within the Markets and Reliability Committee.[44]

At its March 18, 2009 meeting, the Markets and Reliability Committee voted on the PJM Straw Proposal[45] as well as another stakeholder revised proposal. Both proposals failed.[46]

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[44] *See* Draft Minutes from the February 25, 2009 PJM Interconnection Markets and Reliability Committee meeting, at 1 (Mar. 18, 2009), *available at* http://www.pjm.com/committees-and-groups/committees/~/media/committeesgroups/committees/mrc/20090318/20090318-item-01-minutes-20090225.ashx.

[45] PJM Straw Proposal for Compensation Paid to Demand Resources Providing Demand Reductions in the Economic Load Response Program (Mar. 18, 2009), *available at* http://www.pjm.com/committees-and-groups/committees/~/media/committees-groups/committees/mrc/20090318/20090318-item-05-pjm-strawproposal-for-compensation.ashx.

[46] *See* Draft Minutes from the March 18, 2009 PJM Interconnection Markets and Reliability Committee Meeting, at 6 (Apr. 23, 2009), *available at* http://pjm.com/committees-and-groups/committees/~/media/committeesgroups/committees/mrc/20090423/20090423-minutes.ashx.

Even though no proposal garnered a sector-weighted majority, all proposals were forwarded to the Members Committee for vote at the June 4, 2009 Members Committee meeting.[47] There, PJM Members voted on all four proposals, plus the current Economic Program provisions.[48] Again, none of the proposals obtained a majority vote. The results were as follows:[49]

	Sector-weighted Vote
PJM Straw Proposal	2.09 in Favor
Industrial Customer Proposal	2.36 in Favor
FirstEnergy/PHI/Allegheny Proposal	2.08 in Favor
Exelon/PSEG Proposal	1.42 in Favor
Status Quo	2.05 in Favor

Despite the lack of stakeholder consensus, recognizing the importance of moving forward with demand response initiatives, the PJM Board voted at its June

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[47] *See* PJM Interconnection Members Committee Agenda (June 4, 2009), *available at* http://www.pjm.com/committees-and-groups/committees/~/media/committeesgroups/committees/mc/20090604/20090604-agenda.ashx.

[48] A matrix detailing the outcome of these individual attribute votes may be found on the PJM website. See Demand Response Compensation Proposals (June 4, 2009), *available at* http://www.pjm.com/committees-and-groups/committees/~/media/committees-groups/committees/mc/20090604/20090604-item-04-proposal-matrix-final.ashx.

[49] *See* Draft Minutes from the June 4, 2009 PJM Interconnection Members Committee Meeting (Aug. 13, 2009), *available at* http://www.pjm.com/committees-and-groups/committees/~/media/committees-groups/committees/mc/20090813/20090813-item-02a-draft-minutes-june-04.ashx.

24, 2009 meeting to suggest to the Commission a compromise solution to resolving this proceeding, including revisions to the Economic Program to strengthen the position of demand response in the PJM energy markets.

C. Demand Response Currently Is Underdeveloped

On July 1, 2009, PJM's market monitor issued a report analyzing the barriers to entry to demand response in PJM. In that report, the market monitor stated that the "demand side of wholesale power markets is underdeveloped."[50] The PJM market monitor explained that a "fully functional demand side of the electricity market means that end use customers or their designated intermediaries will have the ability to see real time energy price signals in real time, will have the ability to react to real time prices in real time, and will have the ability to receive the direct benefits or costs of changes in real time energy use."[51] The PJM market monitor further observed that "[t]oday most end use customers do not face the market price of energy," i.e., LMP, and that the "most basic barrier to a fully functional demand side of the market is that not all customers are exposed to the actual incremental cost of energy."[52] The PJM market monitor then

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[50] July 1, 2009 Report at 2.

[51] *Id.*

[52] *Id.* at 3.

stated that the purpose of the Economic Program is to overcome the barrier of customers not facing LMP.[53]

The PJM market monitor further reported a decrease in the growth rate of megawatts registered in the Economic Program.[54] In light of the immature state of demand response as cited by the market monitor, an important goal of the Economic Program is to facilitate and improve the functionality of demand response through the PJM wholesale energy markets while transitioning to a future fully functional price responsive demand paradigm at the retail level. PJM's suggested revisions to the Economic Program described below are designed to further this goal.

III. PJM'S SUGGESTED COMPROMISE APPROACH TO THE ECONOMIC PROGRAM

A. Long-Term Goal For Economic Demand Response

In evaluating the Economic Program, the PJM Board considered its long-term vision for demand response—moving to more extensive price responsive demand at the retail level, rather than dependence on a separate demand response program at the wholesale level. When infrastructure, such as advanced metering technology ("AMI") and enabling technology, such as programmable communi-

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[53] *Id.* at 21.

[54] *Id.* at 24. Table 4 shows registered MW increased from 1,530 to 2,944 from the end of January 2007 to the end of December 2007. for a yearly growth rate of 92 percent. In contrast, registered MW grew to 3,290 by the end of December 2008, a yearly growth rate of 12 percent.

cating thermostats, is in place allowing for extensive price responsive demand, end-use customers will be able to see and react to the real-time price of energy and reap the consequent rewards and risks of their consumption decisions at the margins through dynamic retail rates. The PJM Board believes that price responsive demand, "which allows more customers to respond directly to market prices and to voluntarily reduce their consumption when wholesale prices rise, is the ultimate solution to demand participation."[55] This is consistent with the policy of the United States Congress. As stated in the Energy Policy Act of 2005, "[i]t is the policy of the United States that time- based pricing and other forms of demand response whereby electricity customers are provided with electricity price signals and the ability to benefit by responding to them, shall be encouraged, the deployment of such technology and devices that enable electricity customers to participate in such pricing and demand response systems shall be facilitated, and unnecessary barriers to demand response participation in energy, capacity, and ancillary service markets shall be eliminated."[56]

The PJM Board's goal to support progress towards greater dynamic demand response also is in line with the Commission's goal "to encourage price responsive demand

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[55] Boston Statement at 1.

[56] Energy Policy Act of 2005, Pub. L. No. 109-58 § 1252(f), 119 Stat. 594 (2005).

during high priced energy periods."[57] As the Commission has recognized, "[p]rice-responsive demand moderates price increases for all customers (because some demand is willing to be reduced rather than pay higher prices for energy from more expensive units) and it also helps to check potential market power because it provides a countervailing willingness to reduce demand in the face of high prices."[58]

The details of achieving price responsive demand, however, will need to be addressed primarily by the states. A move toward greater price responsive demand at the retail level requires a coordinated effort among PJM and the states, as well as with utilities and CSPs that can deploy new technologies at the distribution level. To this end, the PJM Board "has specifically directed PJM management to increase efforts in support of initiatives that help bridge the informational and structural gap between wholesale market and retail rates."[59] While PJM and the PJM Board are committed to working with the states and the distribution companies to speed up the transition to price responsive demand,[60] they recognize that achieving it

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[57] *PJM Interconnection, L.L.C.*, 99 FERC ¶ 61,227, at 61,943 (2002); *see also* Order No. 719 at P 16 ("Thus, enabling demand-side resources . improves the economic operation of electric power markets by aligning prices more closely with the value customers place on electric power."); *Cal. Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274, at P 689 (2006).

[58] *Cal. Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274, at P 689.

[59] Boston Statement at 2.

[60] *Id.*

will require time, resources, and additional infrastructure. For example, the state regulatory process to review and approve Smart Grid and AMI technologies and to address the policy issues associated with developing new retail rates that are more closely linked to actual wholesale market signals will take some time to ensure thorough consideration of these issues. Deploying the technology necessary to enable price responsive demand on a significant level will not occur overnight.

During the transition to price responsive demand, improving demand response participation in the wholesale energy markets remains crucial, as it is a valuable component of well-functioning markets.[61] Therefore, to facilitate the transition to price responsive demand at the retail level and because "PJM is committed to establishing demand response as a strong participant in its energy markets,"[62] the PJM Board suggests a compromise to the compensation and settlement rules of the Economic Program described below. The compromise is intended to: (i) emulate the financial incentives and consequences of demand response under

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[61] *See Midwest Indep. Transmission Sys. Operator, Inc.*, 108 FERC ¶ 61,163, at P 376, *order on reh'g*, 109 FERC ¶ 61,157, at P 296 ("Demand response is a critical element of an efficient electric market. As demand response increases, wholesale electric markets become more reliable and wholesale prices become less volatile.").

[62] Boston Statement at 2.

price responsive demand; and (ii) facilitate end-users' capabilities to participate in demand response in as seamless a manner as possible.

B. Description Of PJM's Compromise Modifications To Economic Program Compensation And Settlement Rules That Will Encourage Demand Response[63]

PJM suggests three main revisions to the Economic Program compensation and settlement rules. First, it suggests changing the compensation for demand reductions by Economic Program participants from the current rate of LMP less both the generation *and transmission* components of the retail rate to LMP less *only* the generation component. Second, it suggests revisions to expose Fixed Price Customers and Day-Ahead LMP Customers to charges when they self-schedule and submit requests for settlements but fail to reduce consumption. Third, PJM suggests that Economic Program participants receive incentive payments when they reduce consumption during the highest-priced nine percent of hours. This incentive would be temporary. It would remain in place only until there is an additional amount of new price responsive demand capability (1000 MW) of small and medium-sized end-use customers in PJM, which dem-

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[63] This section of the transmittal letter describes in broad terms the proposed compromise modifications to the Economic Program. Pro forma revised tariff sheets in redline format reflecting changes that would be required to implement PJM's suggested approach are attached as Exhibit A to this transmittal letter.

onstrates the incentive is no longer necessary. These revisions are designed to provide demand resources the same financial incentives and consequences as end-use customers that face real-time market prices as described by the PJM market monitor in its report on demand response barriers.[64] The revisions will create an Economic Program
that, taken as a whole, will encourage demand response under current market structures as well as facilitate the ultimate goal of greater price responsive demand at the retail level.

1. Compensation to Fixed Price Customers that Reduce Demand at the Applicable Zonal LMP Less Only the Generation Portion of the Retail Rate Is Sound and has Significant Stakeholder Support

The current compensation mechanism in the Economic Program that pays Fixed Price Customers for demand reductions at LMP less both the generation *and transmission* components of its retail rate "represents an underpayment of the savings associated with the demand side response."[65] The current Economic Program compensation scheme pays Fixed Price Customers less than the market value of energy by an amount equal to the transmission portion of the retail rate.

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[64] July 1, 2009 Report at 2.

[65] MMU White Paper at 4.

As recognized by the PJM market monitor, the subtraction of both the generation *and transmission* components of the retail rate produces an underpayment.[66] "From a wholesale power market perspective, the optimal payment under the Economic Program would be the LMP less the generation component of retail rates" as "the generation component of retail rates is a substitute for LMP."[67] Because Economic Program participant's "payments are reduced by the generation component of retail rates when load is reduced, the appropriate payment is the LMP less the generation component of retail rates because it ensures that the customer receives a total benefit equal to the LMP, the wholesale market-based value of power."[68] Stated differently, from a wholesale energy market perspective, the demand resource receives a direct payment of LMP less the generation component of retail rates plus the avoided cost of the generation component of retail rates by not consuming energy for a total value of LMP accruing to the demand resource.

Therefore, optimally, a Fixed Price Customer should receive a wholesale market payment of LMP less only the generation portion of its retail rate (LMP-G).[69] In that manner, a Fixed Price Customer

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[66] *Id.*

[67] *Id.*

[68] *Id.* at 5.

[69] *See* MMU White Paper at 4.

would receive the market value of the savings achieved by its reduction in load, giving it the same incentive to reduce load as current LMP-based Customers. Fixed Price Customers should be in parity with LMP-based Customers that save the entire amount of LMP through the avoided cost of consuming energy when they reduce load.[70] In short, the Fixed Price Customers should receive the same savings as LMP-based Customers and have the same incentives to engage in demand response.

Importantly, from a wholesale energy market perspective, a reduction in energy consumption does *not* affect the *cost of transmission*; therefore, the transmission component of the retail rates does not "reflect wholesale generation resource savings when a customer reduces load."[71] The market value of generation is LMP and does not include any costs or savings related to transmission or distribution infrastructure. Reducing demand does not change the amount of existing transmission or distribution infrastructure in the ground and, therefore, creates no savings with regard to the recovery of the costs for such infrastructure. By reducing demand, a customer does not reduce the need for existing transmission or distribution

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[70] Day-ahead LMP Customers that respond in the Day-ahead Energy Market avoid paying day-ahead LMP while Real-time LMP Customers that respond in the realtime market avoid paying the real-time LMP.

[71] MMU White Paper at 4.

infrastructure or the amount it must pay for such infrastructure.

To place LMP-based Customers and Fixed Price Customers on more equal footing, PJM's proposal would compensate Fixed Price Customers for the load reductions at LMP less only the generation component (and not the transmission charge) of their retail rates (LMP-G). This will alleviate any underpayment to the Fixed Price Customer and treat Fixed Price Customers and LMP-based Customers similarly regarding compensation for demand response. With this change, Fixed Price Customers will have the same incentives to engage in demand response as LMP-based Customers because they, like LMP-based Customers, will receive the market value of their demand response.

The concept of paying LMP less the generation portion of retail rates (LMP-G) received considerable stakeholder support. In spite of the wide differences between industrial customers and the EDC Group, there was agreement that compensation for Fixed Price Customers should be LMP-G.[72] Moreover, compensation at LMP-G was a part of all competing proposals voted on by the PJM Members Committee,[73]

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[72] *See* PJM Economic DR Program Compensation (July 25, 2008), *available at* http://www.pjm.com/committees-and-groups/committees/~/media/committeesgroups/committees/drsc/20080729-item-02-dsr-compensation-proposal.ashx.

[73] *See* Demand Response Compensation Proposals, at 3 (June 4, 2009), *available at*http://www.pjm.com/committees-and-groups/

and conservatively could be said to have garnered at least a three-quarters majority approval.[74]

2. Changes to the Settlement Rules that Charge Fixed Price Customers and Day-ahead LMP Customers for Failures to Reduce Are Appropriate and have Considerable Stakeholder Support

Under the current Economic Program, Fixed Price Customers and LMP-based Customers whose retail rates are based only on day-ahead LMPs ("Day-ahead LMP Customers") are treated differently from LMP-based Customers who have retail rates based on real-time LMP ("Real-time LMP Customers") regarding failures to reduce. Moreover, Fixed Price Customers and Day-ahead LMP Customers' participation in the markets is treated differently depending on whether they are committed for reduction in the Day-ahead

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committees/~/media/committeesgroups/committees/mc/20090604/20090604-item-04-proposal-matrix-final.ashx.

[74] In addition to voting on entire proposals, votes were held on specific attributes of proposals. The base compensation attribute of LMP-G was included in the "All Remaining Attributes" category, which under the PJM Straw Proposal received 75.64 percent in favor, with 10.26 percent in favor of the current tariff and 14.1 percent abstaining. *See* Draft Minutes from the June 4, 2009 PJM Interconnection Members Committee Meeting, at 91-8 to 91-9, *available at* http://www.pjm.com/committees-and-groups/committees/~/media/committeesgroups/committees/mc/20090813/20090813-item-02a-draft-minutes-june-04.ashx.

Energy Market or self-schedule in the Real-time Energy Market.

A Real-time LMP Customer that wants to reduce its usage over a given time period will be rewarded for doing so in the form of the avoided cost of energy at LMP. But if the Real-time LMP Customer actually consumes more energy than it had intended, it will pay the LMP for the energy it actually consumed. However, under the current Economic Program, Fixed Price Customers and Day-ahead LMP Customers that submit a request for settlement for demand reductions in real-time do not face the same consequence. If the Fixed Price Customer or Day-ahead LMP Customer on net over the day has consumed more than its CBL, the customer need not pay for its extra consumption at the real-time LMP as the Real-time LMP Customer would, but while it continue to receive the benefits of demand reductions payable at the real-time LMP.[75] Consequently, for reductions made in real-time, Fixed Price Customers and Day-ahead LMP Customers are not treated the same as Real-time LMP Customers with respect to real-time energy reductions. In addition, because there is no downside risk to submitting settlement requests for Fixed Price Customers and Day-ahead LMP Customers even if on net they have consumed more than their CBL, Fixed Price Customers and Day-ahead Customers have the incentive to submit settlement requests on a daily basis in the hope that consumption might be below the CBL although no conscious action to reduce demand has actually taken place.

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[75] Operating Agreement, Schedule 1 § 3.3A.4(c).

In the Day-ahead Energy Market, Fixed Price Customers and Day-ahead LMP Customers that have demand reductions committed in the Day-ahead Energy Market and then deviate from the day-ahead scheduled demand reductions in real time are charged or credited for such variance at the real-time LMP plus or minus an amount equal to the applicable balancing operating charge.[76] In contrast, Fixed Price Customers and Dayahead LMP Customers in the Real-time Energy Market are not charged in the settlement process for net charges for failures to reduce below their CBL because, under current rules, their net credits can never fall below zero.[77] Consequently, Fixed Price Customers and Day-ahead LMP-based Customers participating in the Real-time Energy Market (i) are not exposed to the same risks as when they participate in the Day-ahead Energy Market; (ii) are not exposed to the same risks as Real-time LMP Customers; and (iii) the settlement provisions provide incentives for gaming that does not represent real demand response.

Therefore, PJM suggests revisions that will require Fixed Price Customers and Day-ahead LMP Customers that self-schedule demand reductions or are dispatched for demand reductions in the Real-time Energy Market and submit requests for settlements to make payments when their accumulated credits are

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[76] *Id.* § 3.3A.5(c).

[77] *Id.* § 3.3A.4(c).

less than the debits they accumulate (when their consumption is greater than their CBL). Such participants also will be subject to debit payments if the applicable zonal LMP is less than the applicable generation charge in the end-use customer's retail rate. The credits and debits will be based on the applicable corresponding hourly zonal LMP (i.e., the LMP where the customer should have reduced) less the applicable generation charges, if LMP is below the incentive payment LMP threshold (the highest nine percent of hours, described below), or LMP if the LMP is above the incentive payment LMP threshold. Any debits will be passed on to the applicable LSE.

The new settlement rules will ensure that self-scheduled Fixed Price Customers and Day-ahead LMP Customers are exposed to the same incentives for, and risks of, reducing demand or failing to reduce as Real-time LMP Customers as well as the same incentives for participation in the Day-ahead Energy Market and the Real-time Energy Market. The new rule also will remove the inducement for participants to game the system by submitting settlements in the hope that their consumption fortuitously will be under their CBLs in enough hours to have positive credits and thus receive payments when they did not actively and consciously undertake actions to reduce consumption. Furthermore, by imposing consequences for failing to reduce after scheduling reductions with PJM, participants will be discouraged from repeatedly submitting settlements even though their consumption is greater

than their CBLs, which results in the artificial upward adjustment of their CBLs and distortion of the customers' true consumption and demand response levels. Finally, the accumulation of debits by a Fixed Price Customer for reducing when LMP is less than the generation portion of its retail rate, eliminates any improper incentive to reduce demand when reductions are not needed (prices are low) and helps to alleviate losses to LSEs that result from the lost revenues resulting from a customer not paying the generation portion of it retail rate and the sale of energy not consumed by the customer at low LMPs.

These suggested changes also had considerable stakeholder support. PJM's suggested revised settlement rules appeared in various versions of the Compensation Sub-Group's proposal.[78] While the FirstEnergy, PHI, Allegheny group proposed a slightly different set of settlement rules in order to deter the gaming discussed above, the settlement rules were largely the same as those proposed by PJM and supported by the PJMICC, except with respect to how debits would be calculated. At the June 4, 2009 Members Committee meeting, the settlement rule change aspect of PJM's proposal received 58 percent approval with an additional 17 percent approval for the similar FirstEnergy, PHI, Allegheny proposal, signifying con-

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[78] *See, e.g.*, PJM Economic DR Program Compensation (July 25, 2008), *available at* http://www.pjm.com/committees-and-groups/committees/~/media/committeesgroups/committees/drsc/20080729-item-02-dsr-compensation-proposal.ashx.

siderable stakeholder support for the compromise proposal put forth by PJM.[79]

3. Re-Introduction of an Incentive Payment for Economic Program Participants when LMPs Are at the Highest Levels Will Strengthen Demand Response Participation in the Energy Markets and Facilitate the Move Toward More Extensive Price Responsive Demand at the Retail Level

In assessing the need for amendments to the Economic Program, the PJM Board was "committed to establishing demand response as a strong participant in its energy markets."[80] To this end, it "approved the re-introduction of incentive payments as an interim measure to enhance progress toward the long-term solution."[81] The proposed incentive is designed to terminate when sufficient progress toward price responsive demand at the retail level is made within the PJM Region.

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[79] Draft Minutes from the June 4, 2009 PJM Interconnection Members Committee Meeting, at 91-9, *available at* http://www.pjm.com/committees-andgroups/committees/~/media/committees-groups/committees/mc/20090813/20090813-item-02a-draft-minutes-june-04.ashx. The FirstEnergy, PHI, Allegheny proposal had higher debits calculated for small deviations than the PJM Straw Proposal, but was otherwise the same.

[80] Boston Statement at 2.

[81] *Id.*

The incentive proposal is as follows. Economic Program participants that reduce load in the hours in which LMP reaches the level that represents the highest-priced nine percent of the hours based on the previous calendar year would receive an incentive payment.[82] They would receive an LMP payment without a deduction for the generation portion of their retail rates. Therefore, the compensation for Fixed Price Customers effectively would be equal to the LMP in the wholesale market at the time of the reduction plus the avoided applicable generation charge (i.e., "G") in its fixed price retail contract. In other words, Fixed Price Customers would receive, through the combination of the Economic Program and the retail rate savings, LMP + G, where G (avoided cost) represents the incentive portion of compensation for demand reductions.

The incentive compensation for Day-ahead LMP Customers and Real-time LMP Customers would be a simple fixed payment of $75/MWh for demand reductions only in the Real-time Energy Market. This fixed payment is designed to treat Fixed Price Customers and LMP-based Customers comparably. For a

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[82] Reductions by Day-ahead LMP Customers would not be eligible for incentive compensation. This restriction will discourage such customers from settling in the Day-ahead Energy Market and receiving an incentive payment, then not actually reducing in real time and thus receiving a subsidy towards its real time energy costs (expended as a result of having to purchase energy at real time LMP because it did not reduce).

Real-time LMP Customer, the generation ("G") portion of its rate is full real-time LMP. Therefore, if it received LMP + G like a Fixed Price Customer, it would receive LMP twice—once through the wholesale demand response payment and once through the avoided cost of purchasing the retail energy at real-time LMP. Moreover, the size of the incentive payment would increase as LMP increases. Similarly, for Day-ahead LMP Customers, the generation portion of the retail rate is the Day-ahead LMP, which on average is equal to Real-time LMP.[83] Consequently, LMP + G on average would result in Day-ahead LMP Customers also receiving LMP twice and receiving incentive payments that increase with LMP. In contrast, Fixed Price Customers would receive only the G portion of their retail rates as the incentive, which does not increase as LMP increases. Therefore, to preserve parity and fairness, rather than receiving the full applicable hourly LMP when it reduces, an LMP-based Customer would receive a fixed payment of $75/MWh of achieved reduction, which represents the average generation and transmission components of the fixed price retail rates in PJM.[84] As a result, the

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[83] *See* 2008 State of the Market Report for PJM, Energy Market Part 1 Section 2, at 83 (2008) (Tables 2-78 and 2-79 show an average difference of $0.28/MWh), *available at* http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2008/2008-som-pjm-volume2-sec2.pdf.

[84] The average retail generation and transmission charge for Fixed Price Customers registered in the Economic Program as of June 24, 2009 was $71.24/MWh. PJM does not have access to the

incentive for both the Fixed Price Customer and the LMP-based Customer that reduces load would be roughly the same: LMP + G for Fixed Price Customers; and LMP + $75 (the average G in PJM) for LMP-based Customers.

PJM has developed a proposed threshold for the hours in which incentives will apply: the LMP level representing the highest nine percent of the hours in the previous year. PJM originally proposed to apply the incentive payments in the highest-priced fifteen percent of hours to address the concern of certain stakeholders that there would be sufficient demand reduction events of four contiguous hours in which the incentives would apply. However, other stakeholders (EDCs, generation owners, and transmission owners) were concerned that the fifteen percent threshold would result in too many hours in which the incentive compensation would apply and offered two proposals: a five percent of highest price hours threshold, and only paying incentives during scarcity.[85]

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data that shows the separate transmission charges of fixed retail rates. However, as an approximation PJM calculated the average transmission charge, based on transmission charges applicable in July 2009, for a customer that has the same load factor as the PJM system in 2008 (62.5 percent) at $3.60/MWh. Given that retail rate caps are soon to expire in some states served by PJM, PJM believes the $75/MWh figure will be representative of the generation portion of retail rates going forward.

[85] *See* Demand Response Compensation Proposals (June 4, 2009), *available at* http://www.pjm.com/committees-and-groups/

Consequently, PJM revised its proposal to compromise between the two positions and proposed a threshold of nine percent of the highest priced hours. As the Commission has stated, "[i]t is reasonable to limit the additional payment incentive for reducing demand to periods when demand is high relative to supply, and not to offer the incentive when supply is ample relative to demand."[86] PJM's compromise provides a reasonable incentive to demand response, without paying incentives in all hours.

The incentive compensation component of the Economic Program would terminate 60 days after PJM has determined that 1000 MW of new price responsive demand capability at the retail level has been added to the PJM footprint.[87] This threshold for termination of incentive compensation in the Economic Program represents a compromise between the use of performance metrics as proposed by the PJMICC and the use of time limits (two to three years) for incentive compensation proposed by PJM and others.[88] PJM would determine when this incen-

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committees/~/media/committeesgroups/committees/mc/20090604/20090604-item-04-proposal-matrix-final.ashx.

[86] *New Eng. Power Pool*, 101 FERC ¶ 61,344, at P 44 (2002).

[87] Once the 1000 MW threshold of new price responsive demand has been met, PJM would provide 60 days written notice of the sunset date of the incentive provisions.

[88] *See* Demand Response Compensation Proposal (June 4, 2009), *available at* http://www.pjm.com/committees-and-groups/committees/~/media/committeesgroups/committees/mc/20090604/20090604-item-04-proposal-matrix-final.ashx.

tive sunset threshold has been met by summing the peak load of each small and medium-sized end-use customer whose peak load

is less than 0.2 MW and which has new price responsive demand capability.[89] Therefore, the incentive program would cease when 1000 MW of small and medium-sized customers with individual peak loads less than 0.2 MW have newly acquired metering technology and a dynamic retail rate structure[90] to enable them to respond to prices in real time.

As of June 24, 2009, there were approximatel 337 MWs of LMP-based contract demand resources registered in the Economic Program.[91] An increase of 1000 MW of small

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[89] As noted, this definition of small and medium-sized customer is consistent with the definition used in the Commission's Staff Report. *See id.* at 21.

[90] A dynamic retail rate structure is any rate structure where prices change in response to wholesale market or system conditions. Examples of such rate structures are real-time LMP-based contracts, block and index (i.e., two part retail rate) where a certain amount of consumption (block) is guaranteed at a fixed rate and any deviations in consumption are settled at the market rate; and critical peak pricing or critical peak rebate rates where the rates are known in advance, but the timing of the critical peak price or rebate is not known in advance. Time of use rates, where the price for consuming at the peak is higher but is fixed and not directly responsive to the wholesale market prices or conditions, are not considered dynamic rates.

[91] 337 MW of LMP-based customers represents only 14 percent of the 2,364 MW registered in the Economic Program as of June 24, 2009.

and medium-sized end-use customer load that can respond based on real-time prices would represent an almost four-fold increase in price responsive demand and would demonstrate that demand response in PJM is moving toward price responsive demand at sufficient levels such that the incentive is no longer required.

As the PJM market monitor has noted, currently the "demand side of wholesale power markets is underdeveloped."[92] It will not be fully functional until "end use customers or their designated intermediaries have the ability to react to real time prices in real time, and will have the ability to receive the direct benefits or costs of changes in real time energy use."[93] The primary barrier to a "fully functional demand side of the market is that not all customers are exposed to the actual incremental cost of energy."[94] To be able to react to real-time energy prices, end-use customers "must have the appropriate meters" that "are capable of measuring, recording and communicating usage at the hourly level or more frequently."[95] As noted above, fully functional price responsive demand will take some time. In the meantime, the incentive will aid to strengthen demand response in the PJM energy markets. The deployment of metering infrastructure

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[92] July 1, 2009 Report at 2.

[93] *Id.*

[94] *Id.* at 3; *see also* Staff Report at xv.

[95] July 1, 2009 Report at 5.

(Smart Grid/AMI) and enabling technologies cannot be achieved immediately and will require capital. The proposed incentive program will help defray the costs of deploying the infrastructure necessary for price responsive demand and thus expedite the transition to more developed demand response.

Simply put, the incentive compensation approach along with the other revisions will strengthen the demand response component in the PJM energy markets and facilitate the transition to greater price responsive demand, thus meeting the PJM Board's goals and improving the impact of demand response on the markets.

IV. CONCLUSION

In accordance with the Commission's encouragement in the *Complaint Order*, PJM identified, analyzed, and worked to resolve remaining issues in the Economic Program. It attempted to arrive at a solution through the stakeholder process. While the stakeholders were unable to reach super-majority consensus, in order to address the underdeveloped state of demand response in the PJM markets, the PJM staff developed and the PJM Board supported a compromise solution that would strengthen demand response and facilitate the transition to price responsive demand at the retail level and ultimately the elimination of wholesale demand response programs as unnecessary. PJM requests that the Commission reconsider its denial of relief in this docket and adopt PJM's comprehensive compromise solution described herein.

Respectfully submitted

/s/ BARRY S. SPECTOR

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UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. EL09-68-000

PJM INTERCONNECTION, INC.

Sept. 16, 2009

COMMENTS AND PROTEST OF DEMAND RESPONSE SUPPORTERS

Pursuant to Rule 211[1] of the Federal Energy Regulatory Commission's ("FERC" or "Commission") Rules of Practice and Procedure, Comverge, Inc.; EnergyConnect, Inc.; EnerNOC, Inc.; the PJM Industrial Customer Coalition; Viridity Energy, Inc.; and Wal-Mart Stores East, L.P. (collectively, "Demand Response Supporters") hereby file these Comments and Protest in the above-referenced proceeding.[2]

I. INTRODUCTION

On August 26, 2009, the PJM Interconnection, Inc. ("PJM") filed a self-styled "Supplemental Report and Submittal of PJM Interconnection, LLC in Support of

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[1] 18 C.F.R. § 385.211.

[2] Each of these individual parties has filed separate motions to intervene in this proceeding.

Further Commission Action on Rehearing." PJM made this filing in Docket EL08-12. As the Commission is aware, EL08-12 is the proceeding in which the PJM Industrial Customer Coalition ("PJMICC") filed a complaint[3] regarding the expiration of certain compensation levels that existed, but were permitted to expire, for demand response in the PJM Regional Transmission Organization ("RTO"). PJMICC's complaint was ultimately denied by the Commission in a 3-2 vote,[4] and its Request for Rehearing remains pending.[5]

PJM's August 26 filing was made in the aforementioned proceeding. Focusing on language in the Commission's order, in which the Commission urged and encouraged parties to "continue discussions to reach an agreement on an efficient demand response program,"[6] PJM issued its "Supplemental Report." Nevertheless, the "Supplemental Report" goes further than simply detailing stakeholder discussions and identifying remaining issues in the demand response program.[7] In fact, as the Commission concluded when it decided to

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[3] Complaint of the PJM Industrial Customer Coalition, Docket EL08-12 (Nov. 20, 2007).

[4] 121 FERC ¶ 61,315 (Dec. 31, 2007) ("Order Denying Complaint").

[5] Contemporaneously with this filing, PJMICC is filing in Docket No. EL08-12 a Notice of Withdrawal of its request for rehearing, because, *inter alia*, resolution of issues in this Docket No. EL09-68 will obviate the need for Commission consideration of that request for rehearing.

[6] Order Denying Complaint at P 29.

[7] *Id.*

place PJM's "Supplemental Report" in a separate docket[8]—and apparently treat the pleading as a Section 206 Complaint—PJM proposes many changes to its existing Open Access Transmission Tariff ("OATT" or "tariff") provisions addressing compensation for demand response and even provides red-lined revisions to its tariff in a separate attachment.[9]

PJM asserts that these changes are necessary steps to achieve its ultimate goal of having more extensive price-responsive demand at the retail level.[10] Specifically, PJM proposes three general changes to the way in which demand response is compensated under PJM rules. First, PJM proposes to compensate Fixed Price Customers for demand response at Locational Marginal Price ("LMP") minus the generation portion of the demand resource's retail rates, rather than reducing the compensation by both generation and transmission changes as is done currently.[11] PJM argues that such a change: (1) alleviates an underpayment to Fixed Price Customers; (2) results in similar payment to Fixed Priced and LMP-based customers; and (3) provides Fixed Priced Customers the same incentives as LMP-based Customers to

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[8] *See* August 31, 2009 "Notice of PJM Interconnection, LLC's 8/26/2009 Filing of Pro Forma Revised Tariff Provisions."

[9] Hereinafter, Demand Response Supporters will refer to PJM's August 26 filing as a Section 206 Complaint.

[10] PJM Complaint at 54.

[11] *Id.* at 6.

reduce demand.[12] Second, PJM proposes that participants that self-schedule demand reductions or are dispatched for reductions in the Real-Time ("RT") Energy Market would be subject to debit payments when settlement of its daily activity shows that the participants' credits are less than accumulated debits for failure to reduce.[13] Third, PJM proposes to reintroduce "incentive" payments for demand response. PJM's proposal would provide full LMP (i.e., with no questions or transmission offset) payments to customers that reduce consumption in the nine percent of hours when LMP is at its highest level. The "incentive," under PJM's proposal, would sunset when 1,000 new MWs of small and medium-sized end use customers have shown price responsive demand capability in the PJM footprint.[14]

II. BACKGROUND AND COMMENTS

On June 1, 2002, PJM instituted an Economic Load Response Program ("ELRP") in its RT and DA Energy Markets. In 2006, the Commission granted a PJM request to make the ELRP permanent, with certain exceptions.[15] These exceptions included a recognition that certain payments providing for compensation at LMP, by its own terms, will expire at the end of 2007. Accordingly, the Commission-approved provisions in PJM's

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[12] *Id.*

[13] *Id.*

[14] *Id.* at 6-7.

[15] *PJM Interconnection, LLC* 114 FERC ¶ 61,201 (2006).

Tariff stated that "until December 31, 2007, unless extended by a two-thirds sector vote of the Members Committee, [i]n the event the real-time LMP is greater than or equal to $75/MWh, an Economic Load Response Participant that curtails or causes the reduction in demand in real-time will be paid the real-time LMP."[16]

On November 20, 2007, after stakeholder discussions had failed to resolve the impending sunset of certain demand response compensation provisions, PJMICC filed a complaint with the Commission, arguing that expiration of those demand response compensation provisions was unjust and unreasonable and, therefore, a violation of the Federal Power Act.[17] PJMICC asserted that the tariff provisions enabling demand response compensation were necessary, in some form, to ensure adequate levels of demand elasticity in the market and, thus, serve as one of several "checks" on the exercise of market power. PJMICC argued that the rationale for demand response compensation remained valid and at that point experience had shown, and PJM staff itself concluded, that these tariff provisions would continue to provide sustainable value to customers throughout the PJM region.[18]

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[16] *Id.* at P 40-41; *see also* PJM Open Access Transmission Tariff, Section 3.3A.4(d) and 3.3A.5(d).

[17] Complaint of the PJM Industrial Customer Coalition, Docket No. EL08-12 at 1 (Nov. 20, 2007).

[18] *Id.*

[19] 121 FERC ¶ 61,315.

On December 31, 2007, the Commission, over the dissent of two commissioners, issued an order denying PJMICC's complaint.[19] The Commission order, while noting its support for demand response and acknowledging that demand response "makes markets more efficient," nevertheless isolated the many potential issues in the complaint to one: "whether PJMICC has shown under Section 206 of the FPA that the existing PJM tariff provision at issue is unjust and unreasonable."[20] The Commission found that PJMICC had not provided, "besides general statements about the benefits of demand response," evidence that the ELRP payments were required.[21] Accordingly, the demand response compensation provisions were allowed to expire on December 31, 2007.

Commissioner Kelly and then-Commissioner Wellinghoff dissented from the majority's conclusion. The dissenting commissioners refuted the order's characterization of the payment as a "subsidy,"[22] and claimed that the Commission erred by "squandering the opportunity to develop the record regarding cost-effective and appropriate compensation for demand response in PJM's energy market."[23] The dissent found that PJMICC was

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[20] *Id.* at P 23, 25.

[21] *Id.* at P 25.

[22] *Id.*, Dissent at 1 ("As an initial matter, when the benefits to all customers outweigh the costs, there is no subsidy to be borne by other customers.").

[23] *Id.* at 2-3.

correct that the rationale for continuing the payments remained valid and that others—including PJM and the PJM MMU in its 2006 State of the Market Report—indicated that the PJM market had not yet matured and that targeted payments could be considered.[24]

The Commission's December 31 order, while rejecting a call to establish settlement proceedings, did "strongly encourage PJM and the parties to continue discussions to reach agreement on an efficient demand response program."[25] What followed the Commission's decision was an extensive stakeholder process that began first in PJM's Demand Side Response Working Group ("DSRWG") and Demand Response Steering Committee ("DRSC") and eventually transitioned to the portion of the Order 719 Task Force that was assigned items related to demand response. As PJM further outlines in its Complaint,[26] PJM and its stakeholders were in discussions for more than 18 months in an attempt to reach consensus on this issue.

On June 4, 2009, the PJM Members Committee ("MC") voted on demand response compensation proposals that had been vetted in the lengthy stakeholder process. The MC considered four proposals:

- PJM Straw Proposal: LMP minus an offset for generation

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[24] *Id.* at 3 (citing PJM Answer at 2, 6-7).

[25] December 31 Order at 11.

[26] PJM Complaint at 9-16.

- PJMICC Proposal: Full LMP with no automatic sunset
- First Energy/Allegheny Power/PHI Proposal: Full LMP only during highest 5% of hours
- Exelon/PSEG Proposal: Full LMP only during scarcity conditions

The MC also voted on "No Change" to the current tariff.

No proposal gained the required 2/3 sector-weighted majority to be filed by PJM under Section 205. However, the PJMICC proposal received the most support, receiving 49.37% of the MC vote, nearly double the votes received by the PJM proposal (26.58%) and significantly more votes than the utilities' proposals received. Importantly, these votes were sector-weighted votes. In the PJM stakeholder process, generation owners, transmission owners, and electric distribution companies represent 60% of the voting interests. End-use customers and "Other Suppliers" (which includes demand response participants, competitive retail suppliers, and other entities that do not qualify for other sectors) represent 40% of the vote. As a consequence, there is often a substantial bloc vote in the PJM stakeholder process in opposition to meaningful demand response reforms. The outcome of the MC vote is noteworthy because the PJMICC proposal of full LMP with no sunset received the broadest cross-sectoral support.

III. SUMMARY OF ARGUMENT

The future of the electric industry will be quite different than today's status quo. The Congressional emphasis on smart grid technology, demand response, energy efficiency, and distributed sustainable resources represents a turning point in our vision of the future. These new resources can contribute to system efficiency and reliability if the market rules adopted by the Commission are supportive of investments in these technologies. The rules must provide sufficient compensation for these resources to be integrated onto the grid. The potential benefits to society are dramatic, as evidenced in the following Affidavits (Attachments A through E) presented with this Protest.

- **Attachment A**—Affidavit of Dr. Alfred E. Kahn—testifying that the "full LMP" proposal advocated by Demand Response Supporters is not economically inefficient, will contribute to system efficiency, and should be adopted
- **Attachment B**—Affidavit of Dr. Eric E. Woychik—testifying to the central economic principles that justify full LMP compensation for demand response and render "LMP-G" compensation suboptimal
- **Attachment C**—Affidavit of Allen M. Freifeld—testifying to the public policy rationale for adequate compensation of demand response, and explaining why PJM's proposed solution is not just and reasonable

- **Attachment D**—Affidavit of Ron Belbot—testifying from a large industrial customer's perspective on the value of adequate demand response compensation and the impact of such on Severstal Sparrows Point's manufacturing operations
- **Attachment E**—Affidavit of Angela S. Beehler—testifying from a larger commercial customer's perspective on the value of adequate demand response compensation and the impact of such on Wal-Mart's operations

These affidavits fully "develop the record regarding cost-effective and appropriate compensation for demand response in PJM's energy market."[27] The significant changes that the industry is facing, and that the Commission can facilitate, can be illustrated by considering the inter-relationship between increased wind generation and demand response. As the Nation increases its reliance on wind power, a smart grid can provide the bridge to compensate for the intermittent nature of wind power. The smart grid can provide a signal for demand response to reduce load when the wind dies down, so that grid balance is maintained. In the past, there would have been little wind power, and any needed response would have taken the form of ramping up load following fossil generation. In the future, the combination of increased wind power, increased demand response, and smart grid technologies can reduce our reliance on fossil fuels.

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[27] Cf December 31 Order, Dissent at 2-3.

However, this vision of our energy future is dependent upon proper, forwardlooking choices being made by the Commission. The Commission's recognition of the value provided by demand response and the establishment of supportive and non-discriminatory rules and compensation for demand response participation in the markets will facilitate the transition to this new future.

The industry of the future can be far more efficient than the industry of today.[28] Peak loads can be reduced, usage valleys can be filled in, system load factors can be improved, and customers can benefit from all of this if demand response is fairly valued. The industry of the future can exhibit much greater elasticity than it has previously, thus moderating the pressure of increasing prices.

The Commission's National Assessment of Demand Response highlighted the potential of energy efficiency and demand response to reshape loads and our use of energy generally. As the report noted, the potential for demand response exceeds the current level by five times. The potential for avoided generation construction, avoided emissions, and reduced energy expenditures along the entire consumption curve is plain. The economic and environmental benefits of investments in these technologies are within reach if regulatory policies and decision-making are aligned with this objective. Recognizing the value of individual components of the future industry—

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[28] Affidavit of Eric Woychik at 13.

investments in smart grid communications and metering, increased demand response deployment, and others—is a necessary step in bringing these components to market. With respect to demand response, a recognition that LMP represents the value of demand response is a critical decision that is within the Commission's purview to make in this proceeding.

It is against this backdrop that Demand Response Supporters respond to the PJM submission that can only rightly be characterized as a Section 206 complaint. Section 206 of the Federal Power Act requires a complainant to satisfy a dual burden in order to obtain the relief it seeks in a complaint.[29] First, the complainant must establish that the current rate is unjust and unreasonable; second, the complainant must establish that its alternative rate proposal is just and reasonable.[30]

Demand Response Supporters agree that the existing PJM tariff provisions addressing demand response compensation are not just and reasonable and, accordingly, need to be changed. However, PJM has not yet provided the evidence necessary to justify a change, nor has PJM proffered just and reasonable alternatives to the *status quo*. PJM's proposed remedies have not been shown to be just and reasonable (nor has PJM even claimed to make this showing). Accordingly, Demand Response

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[29] 16 U.S.C. § 824e (2006).

[30] See *FPC v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956); *Michigan Electric Transmission Co.*, 116 FERC ¶ 61,164, at P 12 (2006).

Supporters have focused their pleading and the attached affidavits on providing the necessary legal and evidentiary basis to sustain Commission findings that: (1) the current approach to demand response compensation is not just and reasonable; and (2) Demand Response Supporters' proposed remedy is just and reasonable, and is the only just and reasonable remedy in the record.

Demand Response Supporters' proposal is simple. In order to ensure comparability between generation and demand-side resources, compensation for demand reductions must be the full LMP applicable to the demand resource. Offsets to LMP compensation go beyond the jurisdictional limits of, and are irrelevant to, the issues at hand. Full LMP compensation for demand response should not be subject to any sunset or phase-out. As long as generators are being paid LMP, demand resources must be paid LMP. Accordingly, Demand Response Supporters respectfully request that the Commission issue an order: (1) finding that the existing approach to demand response compensation is not just and reasonable, and (2) requiring PJM to adopt full LMP as the just and reasonable compensation for demand reductions.

IV. PROTEST

A. Existing Tariff Provisions Regarding Demand Response Compensation Are Unjust and Unreasonable

1. Current Practice Allows Prices to Be Higher Than Necessary, Which Is Not Just and Reasonable.

The current compensation arrangement stifles demand response participation in PJM, and by doing so perpetuates inelastic demand, which leads to more volatile and higher prices than are necessary. The current compensation arrangement operates as a barrier to demand response, and produces market outcomes that are inefficient; the resulting energy prices produced by PJM's energy market are unjust and unreasonable.[31] PJM's filing essentially concedes that this market failure exists today, and Demand Response Supporters agree.[32] The Commission has an obligation under the Federal Power Act to remedy the elements of PJM's market design that result in unjust and unreasonable market pricing.

As countless studies and analyses have concluded, prices stabilize and demand elasticity increases as more demand response participates in organized electric markets.[33] For example, PJM's IMM recently filed a report with the Commission outlining barriers to demand response in PJM.[34] In this report, the IMM finds that demand elasticity is key to the healthy functioning of the wholesale market.[35] Taking the next logical step, when consumers see prices rising *and are able and willing* to

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[31] Affidavit of Eric Woychik at 5, 6.

[32] PJM Complaint at 3-5.

[33] *See also* Affidavit of Allen Freifeld at 7-8.

[34] "Barriers to Demand response in PJM," ER09-1063 (July 1, 2009).

[35] *Id.* at 2, 4.

respond to such increases, prices overall will moderate as demand lessens. Under the current demand response compensation provision, demand response resources are not able to economically make this rational choice.[36] As a result, more inelastic demand creates higher-than-necessary wholesale market prices, to the detriment of customers and other market participants.

2. Any Generation or Transmission Offset to Full LMP Compensation Is Unjust, Unreasonable, and Unduly Discriminatory.

The current offset for generation and transmission costs[37] effectively requires demand resources to accept a payment for the service they provide that is less than the prevailing LMP This approach is unjust, unreasonable, and unduly discriminatory. It also represents an unexplained departure from the Commission's well-established policy of paying LMP as the just and reasonable rate for offers that clear in day-ahead and real-time energy markets.[38]

The same principles that motivate LMP compensation for generators apply equally to demand response re-

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[36] Affidavit of Allen Freifeld at 18.

[37] PJM Tariff, Attachment K, Appendix Section 3.3A.

[38] *See Sithe/Independence Power Partners, LP v. FERC*, 165 F.3d 944, 950 (D.C. Cir. 1999) (stating that, in order to justify a departure from established policy and precedent, the Commission must find "substantial evidence"); *see also Hatch v. FERC*, 654 F.2d 825, 834 (D.C. Cir. 1981) ("[A]n agency must provide a reasoned explanation for any failure to adhere to its own precedents.").

source compensation. A demand resource responding to, for example, a scheduled or required curtailment is entitled to the established LMP. There is no evidence supporting the payment of something other than LMP. To the contrary, and as Demand Response Supporters' proposal below recognizes, demand response provides substantial value to all customers in many ways, by reducing costs, lowering price volatility, and maintaining reliability. Demand response is entitled to LMP payments for the service provided, just as generators are entitled under current market rules to LMP payment for comparable service. Allowing the current generation and transmission offset violates the Commission's decisions establishing LMP as the just and reasonable rate. Therefore, the generation and transmission offset in the existing tariff is unjust and unreasonable, and unduly discriminatory, as is the pending proposal.[39]

3. Generation and Transmission Offsets Are a Retail Matter, Beyond the Commission's Jurisdiction.

The current approach to demand response compensation in PJM offsets LMP compensation to demand response by the generation and transmission components of

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[39] *See Wisc. Pub. Power, Inc. v. FERC*, 493 F.3d 239, 246 (D.C. Cir. 2007) (noting the Section 205 prohibition of undue discrimination in rates, charges and terms of service, and stating that "[i]n the mid-1990s, FERC determined that longstanding structural barriers to competition in the wholesale power market constituted undue discrimination. Since then, it has been the Commission's policy to eliminate those barriers and promote competition.").

the demand resource's retail rates. To perform this offset, PJM exercises authority given to it by this Commission to determine and calculate the relevant generation and transmission components of retail rates. PJM's tariff essentially presumes, without more, that customers are obligated to pay their load-serving entity for service they do not take. When and how retail customers pay for retail service is a matter of state law and within the jurisdiction of state regulators. PJM also is put in the position of making judgments about retail rate arrangements, including what level of generation and transmission charges are considered for purposes of calculating the generation and transmission offset.

For many reasons discussed throughout this Protest, generation or transmission offsets to LMP compensation for demand response are unjust and unreasonable. At an absolute minimum, delving into retail rate arrangements to force a reduction in LMP compensation for demand resources goes beyond this Commission's jurisdiction. Existing tariff provisions that grant this authority to PJM run afoul of the jurisdictional lines set out in the Federal Power Act. This Commission's jurisdiction extends to the rates for sales of electric energy for resale in interstate commerce, and to practices that reasonably affect those rates.[40] Sales of electric energy, other than for resale, remain within the sole province of state regulatory authorities. Accordingly, the payment for demand response value in the wholesale market is determined by

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[40] § 16 U.S.C. 824e(a).

this Commission, and this Commission's pricing policies require that payment to be LMP. Whether a retail customer owes anything to its retail supplier and, if so, how much, is subject to the exclusive jurisdiction of state regulatory authorities. PJM tariff provisions that pull that responsibility across jurisdictional lines violate the Federal Power Act and, as such, are unjust and unreasonable. All existing PJM tariff provisions that require a generation or transmission offset to full LMP payments for demand reductions must be stricken.

To be absolutely clear, any notion of a generation or transmission offset to LMP compensation for demand response should be considered, if at all, only by state regulatory commissions or other entities with authority over retail rates. It is undisputed that the Commission has broad authority over practices affecting wholesale rates[41] and that the Commission is uniquely positioned and experienced to address wholesale issues.[42] Howev-

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[41] *Id.*; *Connecticut Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (D.C. Cir. 2009).

[42] Demand Response Supporters acknowledge that the District of Columbia Circuit Court of Appeals ruled recently and re-emphasized the Commission's broad authority over practices affecting wholesale rates in *Connecticut Dep't of the Pub. Util. Control v. FERC*, 569 F.3d 477 (2009). However, the Court carefully framed the Commission's jurisdiction in that case, finding that the Commission has the authority to review the Installed Capacity Requirement ("ICR") because the ICR affects wholesale rates. The Court was able to do so by limiting the legal question to whether "setting the ICR represent the kind of direct regulation of generation facilities plainly forbidden by section 201?"

er, the Commission's authority is not unlimited, and, on this issue, state and retail regulatory authorities are uniquely positioned, both jurisdictionally and technically, to determine whether and how transmission and generation offsets to full LMP compensation are appropriate. These offsets are rates typically included in a customer's retail electric contract or found in state-approved electric utility tariffs. The Commission should use this proceeding to remedy the PJM tariff by striking all references that would allow any offset to full LMP compensation for demand response.

4. Insufficient Demand Response Exists in Current Wholesale Markets

As stated in the previous Section, even minimal amounts of demand response participation in wholesale markets can have substantial positive impacts. Despite the potential for benefits that demand response has shown, it is currently an under-developed and underutilized resource in wholesale markets, including PJM. This is a point with which PJM agrees in its Complaint.[43] The IMM has consistently pointed out that the demand side of wholesale electricity markets in PJM is "underdeveloped."[44] Even though Demand Response

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[43] PJM Complaint at 16-17.

[44] 2008 State of the Market Report for PJM, Monitoring Analytics, LLC, Internal Market Monitor for PJM (Mar. 11, 2009) at 93; 2007 State of the Market Report, Market Monitoring Unit (Mar. 11, 2008) at 10, 93; 2006 State of the Market Report, Market Monitoring Unit (Mar. 8, 2007) at 93; Barriers to Demand Side Response in PJM,

Supporters, PJM, and the IMM differ on the optimal method to achieve a more robust demand side of the wholesale market, the parties agree that "wholesale markets will work better when a significant level of demand-side response is available in the market."[45]

Similarly, in a report to Congress in the wake of the enactment of the EPAct of 2005, the U.S. Department of Energy ("DOE") made several important findings, noting that "[l]imited demand response capability exists in the United States," and that the trend-line gave no reason for optimism.[46] The DOE reported that total load management capability had fallen by nearly one-third since 1996 for several reasons, including the fact that fewer utilities were offering load management services.[47]

Demand response is characterized as "underdeveloped" not only because of the actual level of penetration of demand response in wholesale markets is low, but also in recognition of the many significant benefits that demand response can provide, as recognized throughout this Protest.[48] Increasing demand response in the PJM wholesale

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Monitoring Analytics, the Independent Market Monitor for PJM (July 1, 2009), Docket No. ER09-1063-000 at 27.

[45] 2008 State of the Market Report at 93; PJM Complaint at 4.

[46] "Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them,' A Report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005, U.S. Department of Energy (Feb. 2006).

[47] *Id.* at xii.

[48] PJM Complaint at 5, 20.

market, therefore, should be of paramount concern to the Commission, and increasing opportunities to encourage demand response resources to seek to participate by fully compensating them for the benefits they bring to the market is a necessary part of the solution.[49] The status quo, which hinders such robust participation by inadequately compensating demand response should be found to be unjust and unreasonable, and the Commission should adopt Demand Response Supporters' proposal as a just and reasonable remedy.

5. The Economic Demand Response Program Has Experienced a Marked Decrease in Participation Since Full LMP Compensation Was Allowed to Sunset.

Full LMP compensation for demand response should be reinstated to restore levels of demand response in PJM to pre-2008 levels and beyond. As PJM notes in its Complaint, "[s]ince the Commission issued the *Complaint* Order, the PJM market monitor also has observed a decrease in settled demand reductions."[50] PJM's Complaint further reports that settled demand reductions decreased by 35.8% from 2007 and continued to decline through this year.[51] Demand Response Supporters agree. In fact, the available data does indicate that participation in the economic demand response program

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[49] Affidavit of Alfred E. Kahn at 6; Affidavit of Eric Woychik at 11-12.

[50] PJM Complaint at 3.

[51] *Id.*

has seen a marked decrease since full LMP compensation to demand resources was allowed to sunset in December 2007. A realworld example of this is stated in the attached affidavit of Ron Belbot. Mr. Belbot explains that, prior to the expiration of the compensation program, Severstal Sparrows Point was the "largest single site participant and a significant part of the total economic demand response in the BGE zone."[52] After the expiration, curtailment was no longer economic.[53] In addition, the Monitor (IMM) has recently reported on this issue. In its July 1, 2009 filing in PJM's Order 719 compliance proceeding, the IMM concluded that:

> In the Economic Load Response Program, settlement MWh and credits decreased significantly in 2008 compared to 2007, and have further decreased through March of 2009. Other indications of participation, such as registrations, submitted settlement days and active customers, showed some level of stability and even moderate growth for the full calendar year following the elimination of the incentive program, but most of these indicators have shown decreases from December 2008 through March 2009 . . In the Economic Program, total MWh reductions and credits to CSPs decreased in 2008 compared to 2007. In 2007, there were 714,100 MWh of reduction accounting for $49.0 million in total credits, including incentive payments, $31.6 million in credits, not in-

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[52] Affidavit of Ron Belbot at 2.

[53] *Id.*

> cluding incentive payments. In 2008, there were 458,300 MWh of reduction accounting for $27.3 million in credits. Total MWh reductions decreased 35.8 percent and total credits decreased 13.6 percent. MWh reductions and credits continued to decline through March of 2009.[54]

Despite these data, the IMM stated that the evidence did not prove that the removal of the "incentive" payment drove the decrease in participation, citing other factors such as an improved customer baseline level ("CBL") and verification process.[55] We would also expect other parties to suggest that external factors, such as the economic decline, also contributed to the decrease set forth in the statistics provided by the IMM.

These arguments, while superficially plausible, miss the point. It cannot be clearer that since the compensation methodology was permitted to sunset in 2007, the PJM energy market has witnessed a dramatic decrease in demand response participation. By allowing the existing tariff methods to continue in their present form, the Commission would be stifling an important tool at a critical time, and perpetuating a market design that results an unjust and unreasonable rates.[56] Demand response is a key tool to help counterbalance the expected growth in

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[54] "Barriers to Demand Side Response in PJM," Monitoring Analytics, the Independent Market Monitor for PJM, Docket No. ER09-1063 at 22 (July 1, 2009).

[55] *Id.* at 22-23.

[56] Affidavit of Allen Freifeld at 18.

electricity demand both in PJM and throughout the United States. Countless studies and analyses have concluded that demand is expected to rise significantly in the next twenty years and that measures need to be taken to slow and decrease this growing threat. For example, the Electric Power Research Institute ("EPRI") recently forecast that electricity consumption in residential, commercial, and industrial sectors would grow at an annual rate of 1.7% from 2008 through 2030, with consumption increasing by 26% over that period.[57] EPRI also estimates that peak demand would increase by 39% over that period.[58] Similar projections have been made by the American Council for an Efficient Economy[59] ("ACEEE") and FERC Staff.[60] Each of these representative studies concludes that demand response, along with energy efficiency measures, could have a considerable impact on moderating the expected growth in demand. The Commission should, therefore, approve market reforms that encourage the participation of demand response and remedy the observed market failure that is stifling demand response participation.

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[57] "Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S.," Electric Power Research Institute, Executive Summary at 7 (January 2009).

[58] *Id.*

[59] "Assessment of Achievable Potential for Energy Efficiency and Demand Response in U.S. (2010-2030)," ACEEE Summer Study on Energy Efficiency in Buildings (2008).

[60] "A National Assessment of Demand Response Potential," Staff Report, Federal Energy Regulatory Commission (June 2009).

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In summary, PJM existing tariff provisions have not prompted adequate levels of demand response, have allowed market-clearing prices to be higher than necessary, stray into territory reserved for state retail regulatory authorities, and have hindered demand response growth in PJM's energy markets. The Commission has substantial evidence before it to find that the existing tariff provisions are unjust and unreasonable. The Commission should next proceed to fashion an appropriate remedy. To that end, Demand Response Supporters next explain why PJM's proposed remedy has not been shown to be just and reasonable, and why Demand Response Supporters' proposed remedy is the correct solution to the problem.

B. PJM's Proposed Remedy Has Not Been Shown To Be Just and Reasonable

1. PJM's Demand Response Compensation Proposal Is Premised On an Unsubstantiated Expectation of Market and Infrastructure Reform.

PJM states that its proposed modifications to the current demand response compensation are only meant to be interim in nature, and serve as a conduit to its ultimate "long-term vision for demand response."[61] In the long-term, PJM seeks to move to what it refers to as "price responsive demand," and away from a reliance on demand response at the wholesale level. PJM believes

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[61] PJM Complaint at 18.

that such devices as advanced metering technology, which it presumes will allow enduse customers to see and react to real-time pricing signals, "are the ultimate solution to demand participation."[62] PJM also states that this "dynamic response" capability furthers the Commission's goal to encourage price responsive demand during high energy priced periods. However, PJM acknowledges that deploying the technology necessary to enable price responsive demand necessarily will be addressed "primarily by the states," and "will not occur overnight."[63]

PJM presents no evidence supporting its claim that infrastructure enhancements and dynamic pricing at the retail level will supplant demand response's vital role and benefits to energy markets. PJM merely theorizes that, when advanced metering is sufficiently saturated in the jurisdictions that comprise PJM's footprint, it will necessarily deliver the same benefits that robust demand response currently provides (and could provide more deeply if compensated as we propose). PJM makes an unacceptably large leap of faith that it can predict when future market conditions will warrant elimination of the proposed compensation mechanism. PJM claims that a threshold of 1,000 MW of demand response *capability* will be sufficient to support elimination of LMP compensation for demand response. Again, PJM presents absolutely no evidence in support of this proposition or its chosen

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[62] *Id.* (citing Statement of Terry Boston, President and CEO, on behalf of PJM Board of Managers (June 26, 2009)).

[63] *Id.* at 20.

threshold. PJM's proposal is arbitrary and capricious; Commission approval of PJM's proposal would also be vulnerable to challenge as being arbitrary and capricious.[64]

PJM's vision is also plagued by a central fallacy. Even in the unlikely event that PJM's vision of widespread dynamic pricing at the retail level, supported by ubiquitous deployment of smart meters, were to occur, adequate compensation for economic demand response would still be necessary.[65] Dynamic pricing tariffs administered by regulated utilities at the state level would treat differently-situated customers similarly. The necessary consequence is that any such tariff will be attractive to—and work for—some customers, but will be unattractive to others.[66] Indeed, it is likely that one of the reasons that the PJM "vision" has not appeared after nearly a century of electricity regulation is precisely because dynamic pricing does not "work" for so many customers.

It can be expected that those customers for whom dynamic pricing does not work will seek non-dynamic alternatives. In states where competitive options are available, they will seek fixed-rate arrangements. In those states where competitive options are not available,

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[64] *See* 5 U.S.C. § 706; *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29 (1983).

[65] Affidavit of Allen Freifeld at 3-4.

[66] Affidavit of Angela S. Beehler at 1-2.

they will strenuously resist efforts by regulators to force upon them unattractive rate structures. In any event, there will be large subclasses of customers that will not reduce their consumption in direct response to prices. PJM's "vision" myopically ignores this reality.

The existence of wholesale economic demand response rules that are open to and non-discriminatory to aggregators of retail customers ("ARCs"), and enable adequate demand response compensation (at full LMP), will allow ARCs to develop and deploy economic demand resources products that are tailored to the particular needs and circumstances of individual customers. In essence, ARCs can develop "time-varying dynamic pricing tariffs" that essentially duplicate the incentives provided by dynamic prices only during those times when doing so "works" (e.g., is beneficial) for customers. Even if they had the expertise or the inclination to do so, this is a function that regulated utilities may be unable to offer for legal or policy reasons.

We are led to the conclusion that there will always be customers to whom dynamic rates do not apply, or for whom such rates do not work or do not work during all hours of the year. Absent the existence of compensatory wholesale economic demand response opportunities and the ability of ARCs to enroll consumers in them, cost-effective demand response will be unnecessarily restricted and customers will be disenfranchised. For this reason, PJM's proposal to cease adequate demand response compensation when PJM-defined demand re-

sponse capability reaches an arbitrary level of 1,000 MWs cannot be deemed a just and reasonable remedy to the problems that exist with current rules.

2. PJM's "Compromise" Modifications to the Current Compensation and Settlement Rules Are Not Just and Reasonable.

a. PJM's Proposal to Set Compensation at LMP Minus Generation is Not Just and Reasonable.

PJM avers that the current compensation mechanism in the Economic Program (LMP minus generation and transmission) "represents an underpayment of savings associated with the demand side response."[67] Demand Response Supporters agree. However, PJM proposes to correct the current method by removing only transmission costs from the offset to LMP. PJM reasons that "from a wholesale energy market perspective, the demand resource receives a direct payment of LMP less the generation component of retail rates plus the avoided cost of the generation component of retail rates by not consuming energy for the total value of LMP accruing to the demand resource."[68]

PJM's proposal falls far short of remedying the unjustness and unreasonableness of the current approach. As discussed in Section C *infra*, the proper payment for demand reductions is full LMP (i.e., with no generation or

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[67] PJM Complaint at 22 (citing the Market Monitor's June 8, 2008 White Paper, at 4).

[68] *Id.* at 22-23.

transmission offset).[69] The generation offset, not unlike the current offset for transmission, is tied to rates on a retail level, not to Commission-jurisdictional wholesale rates. Even if PJM's proposal would result in comparable compensation, which it does not, such an offset essentially and improperly requires a party to pay for a service that it has not used, in violation of the Commission's cost-causation principles. As the Seventh Circuit Court of Appeals recently observed, "[A]ll approved rates [must] reflect to some degree the costs actually caused by the customer who must pay them."[70] In addition, such an offset causes a demand response participant to incur charges in a manner and to an extent not incurred on the part of a generation resource, violating the spirit of the Commission's call for "comparability" in the treatment of demand resources and generation resources. Finally, as discussed above, Commission orders allowing RTOs to adjust retail rates, or to require customers to pay retail rates for service not taken, exceeds the Commission's authority under the Federal Power Act and, as such, is unlawful. Any consideration of an offset must be undertaken by state regulatory commissions or other retail

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[69] Affidavit of Alfred E. Kahn at 5-6.

[70] *Illinois Commerce Comm'n v. FERC*, Slip. Op. No. 08-1306 (7th Cir. Aug. 6, 2009) (citing *KN Energy, Inc. v. FERC*, 968 F.2d 1295, 1300 (D.C. Cir. 1992)).

regulatory authorities that have lawful authority to consider it.[71] No offset can or should be considered here.

b. Limitations On LMP Payments To The Highest-Priced 9% of Hours and Capped at $75/MWh Are Not Just and Reasonable.

PJM proposes that Economic Program participants that reduce load in the hours in which LMP reaches the level representing the highest-priced 9% of hours based on the previous calendar year would receive a payment of LMP with no deduction for the generation portion of their retail rates. PJM's filing reveals that the 9% figure is justified only as a compromise between some parties' settlement proposal of 15%, and other parties' proposal of 5%.[72] PJM also proposes that payments at full LMP would only be available for Fixed Price Customers. DA LMP Customers and RT LMP Customers would receive a

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[71] While generation and transmission offsets are matters for state regulatory authorities to decide, Demand Response Supporters do not concede that such offsets are reasonable or appropriate. Fundamentally, demand response resources should not be required to pay for energy and capacity they do not consume, and offsets necessarily presume otherwise.

[72] Achieving a "compromise" is not the objective of the PJM market design. The objective must be a market design that produces just and reasonable rates consistent with the statutory requirements of the Federal Power Act. While it is certainly desirable that PJM market participants should attempt to compromise on the means to achieve a just and reasonable market design, compromise for the sake of compromise is not the objective.

$75/MWh payment for demand reductions, and only in the RT Energy Market.[73]

No percentage limitation on demand response can be justified. While different parties offered different percentages in hope of reaching a compromise, no compromise was reached that garnered the necessary 2/3 sector-weighted vote in support. The issue now turns to whether any percentage limitation can be justified outside the context of a stakeholder consensus or settlement. The answer is no.

Demand response can and does provide value at all points of the supply curve. Just because demand response is less likely to be offered and deployed as the supply curve begins to flatten does not mean that demand response compensation must or should cease at that point. The nature of the market is that each resource has a pricing point at which it is no longer economical for that resource to offer. This is true to demand response as well. Demand Response Supporters urge the Commission to let market dynamics work, so that demand resources can self-determine the point at which LMP payments will not provide sufficient value to engage in a demand reduction. Indeed, both Mr. Belbot and Ms. Beehler acknowledge this practical point.[74] Limiting demand response compensation to an arbitrarily-defined percentage of hours cannot be defended.

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[73] PJM Complaint at 30.

[74] Affidavit of Angela S. Beehler at 3; Affidavit of Ron Belbot at 2.

Claims that a percentage-hours limitation is necessary to ensure that demand is actually responding are similarly unsubstantiated. To the contrary, such claims have already been addressed by this Commission's recent approval of new measurement & verification ("M&V") rules for PJM.[75] PJM proposed the M&V revisions after becoming aware that its existing economic demand response program protocols required enhancements. Specifically, PJM noted that the M&V rules used to identify a customer's baseline load ("CBL") did not accurately identify end-use customer demand in every instance.[76] The CBL, prior to the revision, allowed for the situation in which a customer reduced load and received compensation, even though the customer would have reduced load under "normal operations." PJM's proposal, therefore, tightened the CBL to protect against the potential for over-compensation of demand response.[77] It also introduced a code of conduct, which authorizes PJM to suspend demand response participants that engage in anti-competitive conduct.

The Commission accepted PJM's proposal, which is currently in effect. The Commission specifically noted that "PJM's proposed revisions will address [the gaming] concern by ensuring that any given load reduction for which compensation is sought will be based on a market

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[75] *PJM Interconnection, LLC*, 123 FERC ¶ 61,257 (June 12, 2008) ("M&V Order").

[76] *Id.* at 2.

[77] PJM Operating Agreement at section 3.3A.2.

price response, not an invalid, non-price consideration, i.e., a gaming strategy."[78] These protections, combined with market forces that provide a more "natural" value cut-off for demand response, obviate the need for an arbitrary limitation of demand response compensation to a percentage of hours.

The Commission should not allow just and reasonable demand response compensation (at full LMP) to be torpedoed by unsubstantiated and lingering claims that PJM's M&V rules are inadequate. Such claims are a red herring. M&V issues were thoroughly debated in the PJM stakeholder process over several months, were addressed in a PJM filing, were resolved by a Commission order, and have now been implemented and are used in practice. Attempts to confound demand response compensation with additional claims about M&V should be rejected.

The guiding principle Demand Response Supporters urge the Commission to follow is that demand response participants should determine whether the price it sees is "worth" curtailing operations and engaging in a demand reduction. The collective action of these demand response customers making decisions based upon the level of LMP compensation at the time will contribute to proper price formation in PJM's energy market. PJM's approach, by contrast, will allow proper price formation to

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[78] M&V Order at 8.

be distorted by categorical administrative market rules that result in arbitrary discrimination among customers.

PJM's proposed arbitrary cap of $75/MWh is wholly inadequate for a number of reasons. First, the value of demand response in the wholesale market is not a function of the retail contract form, and the compensation to demand response providers should not be discriminatory on the basis of a demand resource's retail contract.[79] As noted above, the retail contract form is beyond this Commission's jurisdiction. Second, the only logical and appropriate payment for demand response service must be the price of energy, and there is only one price for energy in PJM, and that price is LMP. The fixed fee of $75/MWh represents completely inadequate pricing when market prices for energy are $200/MWh or $300/MWh or $400/MWh.[80] Furthermore, placing an artificial "cap" of $75/MWh on payments to LMP-based customers makes little sense in PJM. Capped prices are typically used as a way to mitigate market power. Capping demand response compensation will act as a disincentive to demand response providers, which (as highlighted throughout this protest) act to reduce market power. Compensation

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[79] Compensation to generation does not vary based on differences in fuel contracts from one generator to the next or based on use of different fuels. Gas-fired generators and nuclear generators both receive LMP despite different downstream fuel supply situations. The single clearing price mechanism reflects the value at a point in time of the service provided to the wholesale market. The same rule should apply for demand response. *See* Affidavit of Allen Freifeld at 24.

[80]

proposals other than full LMP for demand response resources are a radical departure from established pricing principles embedded in PJM's market. Such proposals reflect a rejection of the LMP regime, as applied to demand response, and are a far cry from comparability between generators and demand resources.[81]

c. Limiting Compensation to Fixed-Price Customers Is Not Just and Reasonable.

As noted above, PJM also proposes that payments at full LMP would only be available for Fixed Price Customers. DA LMP Customers and RT LMP Customers would receive a $75/MWh payment for demand reductions, and only in the RT Energy Market.[82] Reductions by DA LMP Customers would not be eligible for any incentive. PJM provides no evidence for discriminating based on retail pricing arrangements.

According to PJM, its prohibition on DA LMP customer participation is justified because the restriction seeks to discourage customers from settling in the DA Energy Market and receiving an incentive payment, but ultimately not reducing in real time. To the extent that this perceived concern is *bona fide* (and PJM has not established in the record any evidence to suggest that it is), there could be other means to address it that do not result in rate discrimination. This perceived concern does not justify rate discrimination against one class of

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[81] Affidavit of Allen Freifeld at 23-24.

[82] PJM Complaint at 30.

customers and perpetuating the inelastic demand conditions that render PJM's market inefficient, unjust and unreasonable.[83] If it is a concern, it should be addressed with a scalpel instead of a meat cleaver.

Again, the proposal will severely limit the potential positive impacts of demand response, such as mitigating day-ahead energy prices. Rather than prohibiting demand response bidding by LMP-based customers in the day-ahead market, PJM should be actively promoting such participation, as a means to flatten day-ahead load profiles and more efficiently deploy resources to meet demand.

PJM's stated rationale for these restrictions is "This fixed payment is designed to treat Fixed Price Customers and LMP-based Customers comparably."[84] Several observations are appropriate here. First, it is beyond the Commission's jurisdiction to look at retail contracts to determine wholesale rate issues. PJM erroneously bases its determination on this retail issue, which is properly a matter of state regulatory authority.[85] Second, evaluating compensation available to demand response providers based on an irrelevant factor such as retail rate contracts is rate discrimination.[86] Such an approach violates the

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[83] Affidavit of Eric Woychik at 7.

[84] PJM Complaint at 30-31.

[85] Affidavit of Eric Woychik at 19-20.

[86] A comparable rule for generators would suggest that nuclear generation should receive a relatively low fixed fee for its output, even when LMPs are relatively high based on dispatch of gas-fired

Commission's policy of comparable treatment of market participants. Finally, PJM's concern that paying LMP to LMP-based customers results in too much compensation for these customer, is akin to suggesting that paying high LMPs to generation whose fuel costs are low results in too much compensation to low-cost generation. The Commission has not accepted the latter argument and should not accept the former.

d. Sunsetting Compensation Modifications to Demand Response Compensation Is Not Just and Reasonable.

PJM proposes to terminate full LMP compensation 60 days after PJM has determined that 1,000 MW of new price responsive demand capability at the retail level has been added to the PJM footprint.[87] PJM states that this 1,000 MW threshold represents a compromise between a proposal by PJMICC to review the program after two to three years, and others that sought to use a certain MW threshold. PJM reports that, as of June 24, 2009, 337 MWs of LMP-based contract demand resources registered in the Economic Program.[88] Therefore, according to PJM, 1,000 MWs of small and medium sized end-use customer load would represent a significant increase and demonstrate that PJM is moving toward price responsive

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generation. The proposed rule for demand response providers should be rejected by the Commission, just as the Commission has rejected calls to eliminate the LMP regime for suppliers.

[87] PJM Complaint at 32.

[88] *Id.* at 33.

demand at sufficient levels such that an "incentive" is no longer needed.

PJM's proposal for expiration of any form of full LMP demand response compensation, in whatever form it ultimately takes, is flawed.[89] Demand Response Supporters acknowledge that there may be a point in time at which demand response could become so prevalent as to be less economically-efficient and even cause a reduction in the many benefits demand response brings to the market. PJM attempts to account for this abstract possibility by putting into place sunsetting provisions and artificial caps, instead of acknowledging just how far we are from that time and that the market is best left to work on its own to establish pricing.

In addition, including an arbitrary sunset erects an unreasonable barrier to demand response. PJM makes a preemptive judgment about future market conditions that are unknown and unknowable today, and as such, cannot be just and reasonable.[90] Including arbitrary sunsets will stunt the growth of demand side resources because sunsets inject an unreasonable and disruptive level of uncertainty about the long-term viability of investment. Uncertainty about the stability of the regulatory regime sends highly negative investment signals that drive in-

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[89] As Allen Freifeld asserts in his Affidavit (at 21-22), an artificial and arbitrary "sunset" of demand response compensation will also inevitably chill much needed investment in demand response resources.

[90] Affidavit of Allen Freifeld at 5.

vestment away from demand side business and the technology and infrastructure such companies seek to deploy. It is fundamentally inconsistent with Congressional and FERC policies promoting demand resource deployment in the United States to craft arbitrary sunset provisions that will stifle innovation and investment in demand side resources that is desperately needed today.

Recently, in the IMM's report in PJM's Order 719 compliance proceeding, "Barriers to Demand Response in PJM," the IMM focused squarely on the "underdeveloped" nature of the demand side of wholesale power markets and believes that the markets will continue to be underdeveloped until end-use customers have the ability to respond to price signals on a realtime basis. Specifically, the IMM reported:

> Wholesale power markets will be more efficient when the demand side of the electricity market becomes fully functional . . . A fully functional demand side of the electricity market means that end use customers or their designated beneficiaries will have the ability to see real time energy price signals in real time, will have the ability to react to real time prices in real time, and will have the ability to receive the direct benefits or costs of changes in real time energy use. In addition, customers or their designated beneficiaries will have the ability to see current capacity prices, will have the ability to react to capacity prices and will have the ability to receive the direct benefits or costs of changes in the demand for capacity. When these

> conditions are met, customers can and will make decisions about how much power to use [91]

The IMM went on to suggest that advances in metering and measurement and verification protocols will enable consumers to react to dynamic pricing, and eventually reach these goals.[92] Therefore, using the IMM's analysis, the underdeveloped demand side market is not ready to be scaled back and should, instead, be entitled to the same compensation as supply-side resources and encourage continued growth.

e. Allowing for Debits to Some Demand Resources That Fail to Reduce Demand is Not Unjust and Unreasonable.

PJM proposes revisions requiring Fixed Price Customers and DA Customers that self-schedule demand reductions or are dispatched for demand reductions in the RT Energy Market and submit requests for settlements to make payments when their accumulated credits are less than the debits they accumulate (when their consumption is greater than their Customer Baseline Load). This "debit" idea could also occur if the applicable zonal LMP is less than the applicable generation charge in the customer's retail rate.[93] PJM maintains that this rule would ensure that self-scheduled Fixed Price Customers and DA LMP Customers are exposed to the same incen-

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[91] "Barriers to Demand Response in PJM," at 2-3.

[92] *Id.* at 7-11.

[93] PJM Complaint at 27.

tives for, and risks of, reducing demand or failing to do so as RT LMP Customers and removes the incentive for participants to game the system by submitting settlements in the hope that their consumption will be under their CBLs in enough hours to accrue positive credits and receive payments.[94]

Demand Response Supporters agree that permitting a participant to "game" the system is unacceptable. Demand Response Supporters do not object to some reasonable "debit" approach that recognizes under-provision of committed levels of demand response. For reasons discussed elsewhere, however, the debit approach should not be tied to any retail price levels or any differentials between retail prices and wholesale prices, because retail rates are beyond the Commission's purview.

C. Payment of Full LMP, With No Generation or Transmission Offset, Is Just and Reasonable

1. The Objective of the Federal Power Act is to Provide Electricity at the Lowest Possible Cost to Consumers.

The consumer interest essential to the just and reasonable balance is that of not being subjected to exploitative rates. As the Supreme Court has recognized, the Commission stands as the watchdog providing "a complete, permanent and effective bond of protection from

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[94] *Id.* at 27-28.

excessive rates and charges."[95] Furthermore, the Court reiterated that it "has described utility consumers as the agency's 'prime constituency.'"[96] While the exact boundaries of an exorbitant rate are indeterminate, they must relate to the cost of service[97] and the distribution of associated risk.[98]

The Court of Appeals for the District of Columbia Circuit even more explicitly laid out the importance of the Federal Power Act to protecting end-use consumers. In a decision discussing the powers and duties of the Commission's predecessor, the Federal Power Commission, the D.C. Circuit Court again stressed the notion that the "primary task" of the Commission is to "guard" the consumer from exploitation.[99] Furthermore, the Court went

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[95] *Jersey Central Power & Light v. FERC*, 810 F.2d 1168, 1207 (D.C. Cir. 1987) (citing *Atlantic Refining Co. v. Public Service Commission*, 360 U.S. 378, 388, 79 S. Ct. 1246, 1253, 3 L. Ed. 2d 1312 (1959)).

[96] *Maryland People's Counsel v. FERC*, 761 F.2d 780, 781 (D.C. Cir. 1985) (citing *Federal Power Comm'n v. Hope Nat. Gas Co.*, 320 U.S. 591, 620).

[97] *Farmers Union Central Exchange, Inc. v. FERC*, 734 F.2d 1486, 1502 (D.C. Cir. 1984) (citing *Hope*, 320 U.S. at 602-03, 64 S. Ct. at 287-88), cert. denied sub nom., *Williams Pipe Line Co. v. Farmers Union Central Exchange, Inc.*, 469 U.S. 1034, 105 S. Ct. 507, 83 L.Ed.2d 298 (1984).

[98] *Jersey Central Power & Light*, 810 F.2d at 1207 (citing *Washington Gas Light Co. v. Baker*, 188 F.2d 11, 20 (D.C. Cir. 1950)).

[99] *See Nat'l Ass'n for the Advancement of Colored People v. Fed. Power Comm'n*, 520 F.2d 432, 438 (D.C. Cir. 1975).

on to cite the congressional directives in the Federal Power Act to the role of the Commission:

> Congress's central concern with exploitation is of course reflected in the statute's emphasis on just and reasonable prices, as well as by its frequent references to the financial and accounting aspects of electric power operations. The legislative history of the Act adds little to our understanding. It reveals that Congress's goal was, once again, the 'planned coordination of the facilities of the industry which alone can produce an abundance of electricity at the lowest possible price.'" (footnotes omitted).[100]

Based on the above, it is clear that courts have interpreted the Federal Power Act to require the Commission to ensure that consumers pay as low of a possible cost for electricity. In the demand response context, this mandate means that demand response must be adequately compensated because it provides quantifiable and qualitative benefits to all customers. Full LMP compensation to demand response satisfies this statutory requirement.[101] Full LMP compensation for demand response has firm footing in the Federal Power Act and the line of cases confirming the customer-oriented objectives of the Federal Power Act.

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[100] *Id.*

[101] Affidavit of Alfred E. Kahn at 3, 6.

2. Demand Response Is a "Practice Affecting Wholesale Rates," And The Commission Has Jurisdiction To Set Full LMP as the Appropriate Compensation for Demand Response.

The Commission has broad authority over practices affecting wholesale rates[102] and the Commission has again recently found that demand response is such a practice and that it provides value to the wholesale market. In Order 719, the Commission repeated that, "on numerous occasions, [it] has expressed the view that the wholesale electric power market works best when demand can respond to the wholesale price."[103] In addition, the Commission specifically noted:

> Demand response can provide competitive pressure to reduce wholesale prices; increases awareness of energy usage; provides for more efficient operation of markets; mitigates market power; enhances reliability; and in combination with new technologies, can support the use of renewable energy resources, distributed generation, and advanced metering. Thus,

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[102] *See* § 16 U.S.C. 824e(a); *Connecticut Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (D.C. Cir. 2009).

[103] *Wholesale Competition in Regions with Organized Electric Markets*, 125 FERC ¶ 61,071 at P 16-18 (Oct. 17, 2008) ("Order 719") (citing *New England Power Pool and ISO New England, Inc.*, 101 FERC ¶ 61,344 at P 44-49 (2002), *order on reh'g*, 105 FERC ¶ 61,211 (2003); *PJM Interconnection, LLC*, 95 FERC ¶ 61,306 (2001); *PJM Interconnection, LLC*, 99 FERC ¶ 61,227 (2002); *Southwestern Power Pool, Inc.*, 116 FERC ¶ 61,289 (2006).

> enabling demand-side resources, as well as supply-side resources, improves the economic operation of electric power markets by aligning prices more closely with the value customers place on electric power. A well-functioning competitive wholesale electric energy market should reflect current supply and demand conditions.[104]

Moreover, in the Order on Rehearing, Order 719-A,[105] the Commission rebuffed several parties' attempts to characterize demand response as outside of FERC's authority under the Federal Power Act.[106] Specifically, the Commission rejected arguments by the Transmission Access Policy Study Group ("TAPS") and Joint Petitioners[107] that a retail customer's reduction of energy consumption is neither a wholesale sale of electric energy nor transmission in interstate commerce, and that retail sales are sales of electric energy to end users that are not sales for resale.[108] The Commission also rejected Joint Petitioners' assertion that a promise not to consume electric energy is not covered by the plain language of the

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[104] Order 719 at P 16.

[105] *Wholesale Competition in Regions with Organized Electric Markets*, 125 FERC ¶ 61,071, *order on reh'g*, 128 FERC ¶ 61,059 (2009) ("Order 719-A").

[106] 16 U.S.C. § 824 *et seq.*

[107] "Joint Petitioners" consist, in this instance, of the American Electric Power Corporation; American Public Power Association; and California Municipal Utilities Association.

[108] Order 719-A at P 18.

Federal Power Act. Stating that "wholesale markets work best when demand can respond to the wholesale price," the Commission found that it "began this proceeding with the goal of eliminating [ ] barriers to demand response participation in the organized markets."[109] In summary, the Commission found that:

> Demand response affects public utility wholesale rates because decreasing demand will tend to result in lower prices and less price volatility. The Commission has noted that demand response has both a direct and an indirect effect on wholesale prices. The direct effect occurs when demand response is bid directly into the wholesale market: lower demand means a lower wholesale price. Demand response at the retail level affects the wholesale market indirectly because it reduces a load-serving entity's need to purchase power from the wholesale market. Demand response tends to flatten an area's load profile, which in turn may reduce the need to construct and use more costly resources during periods of high demand; the overall effect is to lower the average cost of producing energy. Demand response can help reduce generator market power: the more demand response is able to reduce peak prices, the more downward pressure it places on generator bidding strategies by increasing the risk to a supplier that it will not be dispatched if it bids a price that is too high. Moreover, demand response enhances system reliability. Thus, because demand re-

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[109] *Id.* at P 44.

> sponse directly affects wholesale rates, reducing barriers to demand response in the organized wholesale markets helps the Commission to fulfill its responsibility, under sections 205 and 206 of the FPA, for ensuring that those rates are just and reasonable.[110]

It is important to point out that, in addition to the Commission's well-established determination that demand response is a practice affecting wholesale rates subject to FERC jurisdiction, Courts have also recognized this critical fact and the broad authority that the Commission has under the Federal Power Act to regulate practices that "affect" public utility wholesale rates.[111]

3. Demand Response Provides Value to the Wholesale Market.

Furthermore, the Commission had identified several areas in which demand response benefits the wholesale markets—lessening price volatility; aiding system reliability; lowering wholesale prices; reducing potential exercises of market power; and increasing competition.[112] Notably, no party challenged these Commission findings, made in Order 719-A, that are generically applicable to the organized markets that are the subject of

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[110] *Id.* at P 47.

[111] *See, e.g., City of Cleveland v. FERC*, 773 F.2d 1368, 1376 (D.C. Cir. 1985); *Connecticut Dep't of Pub. Util. Control v. FERC*, No. 07-1375, slip op. at 14-15 (D.C. Cir. June 23, 2009).

[112] Order 719-A at P 47; *see also* Affidavit of Dr. Eric Woychik at 12 and Affidavit of Allen Freifeld at 12-13. (discussing numerous benefits of increased demand response participation).

Order 719-A, including PJM. Those findings can and should control here.

In addition, the Brattle Group prepared a study, "Quantifying Demand Response Benefits in PJM," showing the many substantial and positive affects demand response can have on PJM's wholesale energy and capacity markets.[113] The Brattle Group study simulated the market impacts of curtailing only 3% of load in the BGE, Delmarva, PECO, PEPCO, and PSEG zones during the top twenty 5-hour price blocks in 2005. It found that:

- Curtailing 3% of each selected zone's super-peak load, which reduces PJM's peak load by 0.9%, yields an energy market price reduction of $8-$25 per megawatt-hour, or 5-8% on average, during the 133-152 hours in which curtailment occurs in at least one zone. The range depends on market conditions.
- Assuming all loads (i.e., customers or their retail providers) are exposed to spot prices, the estimated price reductions could benefit non-curtailed loads in MADRI states by $57-$182 million per year. The potential benefits to the entire PJM system amount to $65-$203 million per year.
- The market impact in each zone would be substantially smaller if it curtailed its load in isolation

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[113] *Quantifying Demand Response Benefits in PJM*, the Brattle Group, prepared for PJM Interconnection, LLC and the Mid-Atlantic Distributed Resources Initiative ("MADRI") (Jan. 29, 2007).

> from the other zones. By the same token, the market impact would be larger if more than five zones implemented DR programs or if greater amounts of DR participation were achieved.[114]

The Brattle Group also estimated that benefits to demand response program participants were significant, even despite the relatively small amount of curtailment. The study stated that benefits would be approximately $85 to $234/MW-hr based on its simulations and, using different assumptions, could result in yearly benefits ranging from $1 to $36 million. In addition, participants would also benefit on the capacity side, as reducing peak demand would flatten the load shape and could produce a long-term capacity benefit of $73 million/yr based, again, on its assumed 3% curtailment of load in the five zones.[115]

On top of these obvious economic benefits, both to PJM's wholesale markets and directly to the demand response program participants themselves, the Brattle study identifies other areas that it recognizes as benefits, but for which it did not quantify. These areas include: enhanced market competitiveness; reduced price volatility; insurance against extreme events; capacity benefits to non-curtailed load through lowering capacity clearing

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[114] *Id.* at 2.

[115] *Id.* at 3.

prices; and environmental benefits, such as lowering emissions at critical times.[116]

Numerous other studies have made similar conclusions regarding demand response benefits.[117] For example, FERC Staff issued its "Assessment of Demand Response & Advanced Metering" in December 2008, outlining the status of demand response programs throughout the country and recommending that the Commission continue to make demand response a priority.[118] Commission Staff further highlighted the "critical role" that demand response has played during system emergencies during 2007:

- Demand response averted a system-wide emergency in California between August 29-August 31.
- On August 8, PJM reached its system peak of 139,428 MW. Emergency demand response provided an 888 MW reduction, and demand response resources in the economic program provided addi-

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[116] *Id.* at 26-30.

[117] *See, e.g.*, Federal Energy Regulatory Commission, *Assessment of Demand Response and Advanced Metering: Staff Report*, Docket No. AD-06-2-000 (Aug. 2006); Federal Energy Regulatory Commission, *Assessment of Demand Response and Advanced Metering: Staff Report*, Docket No. AD (Dec. 2008) ("2008 Staff Report"); United States Department of Energy, *Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them*, A Report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act (Feb. 2006) ("DOE Report").

[118] 2008 Staff Report at 65.

tional reductions, lowering the system peak and LMP.

- On December 12, an unexpected drop in generation of 1,022 MW occurred in Texas. ERCOT's demand response program resulted in a response of 1,051 to stabilize the grid.[119]

In February 2006, the United States Department of Energy ("DOE") issued its report, "Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them," citing the numerous benefits that demand response programs have, and can have, to electric markets. The DOE Report found that the "most important benefit of demand response is resource-efficiency of electricity production."[120] The DOE Report also concludes that demand response results in: (1) participant financial benefits, through bill savings and incentive payments; (2) market-wide financial benefits, due to lower wholesale market prices caused by demand response lessening the need for costly-to-run generators during periods of high demand and longer-term wholesale market benefits such as lower production costs and lower prices; (3) reliability benefits, because demand response lowers the likelihood and consequences of forced outages that would impose financial costs and inconvenience to customers; and (4) market performance benefits, or de-

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[119] *Id.* at 49-53.

[120] DOE Report at vi.

mand response's value in mitigating suppliers' ability to exercise market power.[121]

4. Full LMP Compensation For Demand Response Helps Optimize The Consumer Benefits and Protection Required by the Federal Power Act.

As the previous sections have shown, a minimal amount of demand response produces substantial benefits, both for the demand response participant and the market as a whole. In fact, as the 2007 Brattle Group report has shown, smaller amounts of demand response, when responding to increasing market prices, produce a savings for the market—and, by extension, for consumers—that well exceeds the price paid to the participant. At the highest prices, simple economics dictates that consumers benefit even more from demand response.[122] Consumers, therefore, have much to gain in the way of lower clearing prices from an increase in demand response participation. A rational approach to the compensation of demand resources would compensate demand response up to the point where payments for such resources equals the incremental value of the response to the market (i.e. consumers). This approach would optimize the benefits to the market, while recognizing that it would not be prudent to pay demand response resources more than the market surplus.

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[121] *Id.* at vi and 26-35.

[122] Affidavit of Allen Freifeld at 8.

5. A Generation Offset Should Be Considered, if at all, at the State and Retail Regulatory Level.

A generation offset to full LMP compensation should be considered, if at all, only by state regulatory commissions or other entities with authority over retail rates. While the Commission is uniquely positioned and experienced to address wholesale issues, state and retail regulatory authorities are positioned, both jurisdictionally and technically, to determine whether and how a generation offset to full LMP compensation is appropriate.[123] Generation rates for retail customers, such as the rates that PJM proposes to include as an offset to demand response compensation, are a creature of retail rates, set and approved by the state or relevant retail electric authority. It is a rate typically included in a customer's retail electric contract (in retail choice states) or found in state-approved electric utility tariffs (in non-choice states). Adopting a demand response compensation approach that does not include a generation or transmission offset is just and reasonable, and legally consistent with the Federal Power Act.

6. Arguments that Full LMP Payment Is a "Subsidy" Are Irrelevant, and Incorrect.

Demand Response Supporters preemptively address likely arguments that full LMP compensation for demand response is a "subsidy." In a proceeding currently before the Commission addressing PJM's compliance with

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[123] Affidavit of Allen Freifeld at 25.

Order 719, one party characterized payments made under the current demand response compensation approach as a "subsidy," even with the current generation and transmission offset.[124] Those arguments are likely to become louder as the Commission cures the current faults in the wholesale market by adopting full LMP compensation for demand response.

The payment received by demand resources that perform in the energy market is simply the energy market clearing price at that time, and represents the prevailing market value of the service being provided.[125] Certain parties cast the value of demand resource participation in a negative light by portraying demand response compensation as a "subsidy" that unfairly favors one resource at the expense of another. The Commission should resist these mischaracterizations, and reject any attempt to characterize demand response payments as anything more than the correct valuation of a service that is being provided to the system.

> Members of this Commission have already discussed the issue of "subsidies" relative to demand response compensation. As stated above, in the proceeding denying PJMICC's complaint regarding PJM's economic LRP compensation methodology, two commissioners dissented from the majority's characteri-

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[124] *See* Comments of PSEG, Docket No. ER09-1053 at 4 (June 30, 2009).

[125] Affidavit of Eric Woychik at 20.

zation of demand response payments as "subsidies." In disagreement with the majority's conclusions, Commissioners Wellinghoff and Kelly concluded that the majority "mischaracteriz[ed] the payments at issue [as subsidies] and squander[ed] the opportunity to develop a more complete record, through hearing or settlement judge procedures, on what compensation is appropriate for demand response providers in PJM's energy market."[126] Commissioners Wellinghoff and Kelly further argued that until the December 31 Order, the Commission has never characterized the demand response payments at issue as subsidies.[127] Moreover, the Dissent noted that the Commission "does not explain in [the December 31] order this stark and unsupported departure from our past policy."[128] Commissioners Wellinghoff and Kelly concluded that the Commission should have undertaken procedures to develop the record fully regarding appropriate compensation for demand response.

IV. PROCEDURAL RECOMMENDATION

Demand response delivers its greatest value during typically high-priced periods. In PJM, these periods tend to occur during the heart of the winter (January/February) and the heart of the summer (July/August).

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[126] *See* December 31 Order, Dissent of Commissioners Wellinghoff and Kelly at 1 (hereinafter, "Dissent").

[127] *Id.* at 2.

[128] *Id.*

Demand Response Supporters urge the Commission to take this into account as it determines the procedural course for this proceeding.

Demand Response Supporters firmly believe that substantial evidence has been presented in this proceeding and will be presented in other paper filings, and that further procedures will be unnecessary. The Commission has the authority to resolve the issue based merely on pleadings, provided those pleadings adduce substantial evidence.[129] However, if the Commission requires evidence beyond the substantial evidence that Demand Response Supporters provide here, the Commission should consider scheduling a Technical Conference in near future, with specific guidance on what additional evidence is necessary. Alternatively, and less preferably, the Commission should convene an evidentiary hearing and require that the hearing be conducted on a fast-track basis. Because the issue of demand response compensation has been percolating in the PJM stakeholder process for nearly 20 months, no need exists for extensive discovery. Also, the 20 months spent on the stakeholder process increase the urgency for prompt resolution of the demand response compensation issue.

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[129] *Braintree Elec.Light Dept. v. FERC*, 550 F.3d 6, 13 (D.C. Cir. 2008) (citing *Central Maine Power Co. v. FERC*, 252 F.3d 34, 46-47 (1st Cir. 2001) (gathering cases where courts have approved "hearings by affidavit and nothing more" so long as genuine issues of material fact can be adequately resolved on the written record" (internal quotations omitted)).

Demand Response Supporters urge the Commission to address these issues expeditiously.

V. CONCLUSION

WHEREFORE, Demand Response Supporters respectfully request that the Commission:

(1) Find that PJM's current Tariff provisions addressing demand response compensation are not just and reasonable;

(2) Find that PJM's demand response compensation proposal has not been shown to be just and reasonable;

(3) Find that Demand Response Supporters' approach to demand response compensation, as outlined above and as set forth in the Affidavit of Alfred E. Kahn and other affidavits is just and reasonable; and

(4) Require PJM to make a compliance filing to implement the Commission's findings.

Respectfully submitted,

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Dated: Sept. 16, 2009

ATTACHMENT A

AFFIDAVIT OF ALFRED E. KAHN

Question:

Please identify yourself.

Answer:

I am Alfred E. Kahn, Robert Julius Thorne Professor of Political Economy, Emeritus, at Cornell University; and Special Consultant to National Economic Research Associates, Inc. (NERA).

Question:

Please provide a summary of your background and qualifications.

Answer:

I attach a copy of my curriculum vitae. Among my most relevant credentials are my authorship of the two-volume *Economics of Regulation*,[1] published in 1980-81 and reprinted in 1988—which I believe it is fair to characterize as the standard if not classic statement of the economic case for marginal cost pricing, my former Chairmanship of the New York State Public Service Commission (1974-77) and, immediately following, my Chairmanship of the U.S. Civil Aeronautics Board. In the former position, I in effect took the leadership in an ongoing and

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[1] Alfred E. Kahn, *The Economics of Regulation: Principles and Institutions*, Volume I: *Economic Principles*, published 1970; Volume II: *Economic Principles*, published 1971 by John Wiley & Sons, Inc., New York, NY; reprinted by MIT Press in 1988.

gradually successful effort to apply the principles I had enunciated in Volume 1 of my monograph; in the latter, I took the lead in effectuating the deregulation of the airlines, as the superior method of leaving it to competition, where that seemed to be feasible, to produce those same results. I have also been the Advisor to the President (Carter) on Inflation, and Chairman of the (U.S.) Council on Wage and Price Stability.

I have served also on a variety of other public and private boards and commissions, several of which dealt with environmental issues, including the National Academy of Sciences Advisory Review Committee on Sulfur Dioxide Emissions and the Environmental Advisory Committee of the Federal Energy Administration. I also served on the Executive Committee of the National Association of Regulatory Utility Commissioners, and as Chairman of its Committee on Electric Power. In these several roles, I testified before the Senate Committee on Finance, in successful support of H.R. 6860, "The Energy Conservation and Conversion Act of 1975," July 18, 1975, specifying in particular the obligation of electric distribution companies to purchase the power of qualified independent generating facilities at avoided or incremental costs, in the interest of both environmental protection and energy conservation.

Question:

What is the purpose of your testimony in this proceeding?

Answer:

My clients, the Demand Response Supporters, have asked me whether I would support a proposal that PJM be required to pay subscribers—or aggregators providing demand-response services to ultimate customers—full Locational Marginal Price (LMP), for curtailing their consumption of electricity, especially at times of peak demand, by specific amounts estimated necessary in the aggregate to hold loss-of-load probabilities to optimal levels—minimizing the aggregate cost to all customers by subjecting the entitlement to them to an auctioning process. For all practical purposes I am supporting the "full LMP" aspect of PJM's proposal, although I believe the economics of its supporting argument is not completely correct.

Question:

With which part of PJM's economic reasoning do you disagree?

Answer:

PJM seems to suggest that the first best economic approach to pricing demand-side load reductions requires the wholesale market price be reduced by the generation portion of retail rates. Because of its unsatisfactory experience in electricity demand reductions hitherto, PJM's proposal is to depart from what it conceives to be the economic price and pay the full LMP or market price in order to increase participation by customers in its efforts to match load to resources—a proposal of particular in-

terest when the supply-demand margin is small. I believe PJM's economic rationale is mistaken, but serendipitously, its proposed incentive payments are economically correct.

Question:

Why so?

Answer:

The (incremental) costs saved by curtailments in demand clearly will be full LMP—including the marginal costs of generation. So, in the end, full LMP inducement is the economically correct one.

Question:

But don't such payments—which some might regard as subsidies—usually distort economic behavior and produce inefficiencies?

Answer:

For my former New York State constituents, a sufficient response to your question would probably be "subsidy-schmubsidy." The simple answer in the case of this proposal is that the payments it advocates are not "subsidies" any more than other corrections of prices to equate them to marginal costs. The simple answer in the case of this proposal is that the purpose and effect of the direct payments to purchasers will be to *increase* economic efficiency by facilitating and inducing efficient consumer responses to changing incremental supply costs. In contrast to the usual connotations of subsidization, the

purpose and result here is to induce consumers to behave as they would if the market mechanisms alone were capable of rewarding them directly for efficient economizing. I will leave as questions for another day the possibility that these incentives and institutional arrangements might prove to be inadequate, i.e., whether or not PJM's proposal to give consumers what it regards—incorrectly—as greater than efficient incentives proves nevertheless insufficient to induce or make economic installation of the requisite metering for all customers and what additional remedies may be required—for example to overcome the typical unwillingness of state commissions to subject customers to genuine marginal cost pricing—as PJM recognizes in this proceeding.

There are two, conceptually different reasons why the mere prescription of equating the price of power to marginal supply cost is not a sufficient recipe for maximizing economic efficiency. The first is that incorporating in wholesale price the sharply increasing marginal cost of generation at times of peak demand and the increased probability of system-wide losses of load may be politically, and perhaps economically, infeasible: it would not only require separate meters for every customer reflecting the times and amounts of electric use, moment by moment, hour by hour and day by day,[2] but it would also

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[2] In addition, such meters would have relatively little utility without the ancillary equipment to monitor the current electric price and automatically adjust customer usage in response to it. On the other

require tariffs that pass those constantly varying costs along to consumers. While there are studies suggesting that such metering might be worthwhile in the aggregate—and there is no serious dispute that the cost-benefit ratio would in a small proportion of the customer base be highly favorable—state regulatory authorities have not generally been supportive of such tariff structures.

Second, and quantitatively far more important, is the increasing probability, as output gets closer and closer to physical limits of generating capacity, of losses of load, the costs of which are orders of magnitude higher than the marginal costs of actual generation. Such shortages can come on quite quickly, from unanticipated losses of generating equipment, unanticipated surges in demand, or some combinations of the two. In such cases, the true marginal costs of energy far exceed LMP.

In any event, I am unaware of any reason to question PJM's assessment that their "optimal" price has not to date produced the efficient demand response and that its effectiveness is actually decreasing over time. So either the LMP-G (or the previous LMP-G-T) price is clearly not economically correct or there is some sort of market failure. Since I am unaware of any assertion that there is such a market failure, I believe that the empirical evidence provided by PJM supports my view that PJM is incorrect on what is the "optimal" price.

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hand, universally applied economically efficient time-of-use rates would provide efficient incentives to install such equipment.

These circumstances—specifically, the fact that pass-through of the LMP is costly and (perhaps) politically infeasible,[3] the possibly prohibitive cost of the metering necessary to charge each ultimate user, moment-by-moment, the often dramatic changes in true marginal costs for each—can justify direct payment at full LMP to distributors and ultimate customers who promise to guarantee their immediate response to such increases in true marginal costs of supplying them.

Question:

How does the full LMP proposal of rewarding successful bidders promising to deliver on short notice such reductions in demand as are estimated to be necessary to equate the remaining demand to available supply while holding loss-of-load probability to optimal levels assure the results that would be achieved if universal time-of-day meter-reading were economically feasible?

Answer:

First, this would not be economically inefficient. It would involve confronting customers (or voluntary aggregators of customers) with the true incremental cost of supply, rewarding them to the extent necessary to pro-

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[3] And even if both economically and politically feasible, in the event it is not actually present. Thus, while it might make sense, as PJM proposes, to revisit these incentives when a sufficient amount of load is actually subject to LMP, the fact that a trivial amount of load is subject to LMP passthrough today makes the PJM proposed payments relevant.

duce first- best results. The full LMP plan provides a mechanism for eliciting economically efficient responses from consumers such as would have been achieved were it possible to charge each of them from moment to moment with the varying true marginal cost of supply.

In addition, the existence of this plan gives consumers the incentive to install costly capital equipment to allow aggregators to remotely control equipment and in this way guarantee timely response.

Question:

Doesn't paying all bidders, high and low alike, the *marginal* price necessary to achieve the amount of load shedding necessary to hold the loss of load probability to acceptable levels end up paying many of them more than necessary to elicit the requisite aggregate curtailment?

Answer:

Economically efficient pricing—at the incremental cost of equating supply and demand–always confers rents on infra-marginal suppliers and bidders. The rents in this case are or would be no more than or different from those prevalent in all efficient markets. What the competitive bidding process—just as competition in the supply of all goods and services—ensures is that those rents are held to the minimum necessary to equate demand with supply, while holding the probability of system breakdowns to predetermined optimal—observe "optimal", not zero—levels. What economic efficiency requires is that all suppliers and purchasers confront the same *marginal* cost.

The significant point is that such pricing maximizes net social welfare as the economist defines it: the customers who agree to curtail their usage at peak times are better off because, as is demonstrated by their acceptance of the bids, the value of that compensation to them outweighs the inconvenience of curtailing their usage. All the remaining subscribers are better off as well, because the curtailment of usage reduces, or holds down, the incremental cost of continuing to serve all, while holding the possibility of losses of load and blackouts, highly injurious to all customers, to pre-determined optimal levels.

Society benefits, additionally, by the voluntary reduction, because it puts off the cost of constructing additional generating plants and/or conserves the characteristically heavy use of fuel by peaking generators.

The vision of a power pool inducing individual customers that they are legally obligated to serve to curtail their purchases and paying some more than they would ask individually to curtail their demand may strike the layman as immoral or illegitimate—but that is how a free-price system works, inevitably providing what economists call "rents" to suppliers who would have been willing to provide a large portion of market supplies at lower prices. To induce the supply side of the market to provide output sufficient to meet peak demand clearly confers "rents" on lowcost producers or, strictly, on a large portion of supply that would have been forthcoming at lower prices. It is necessary, similarly, in the event of an increase in demand: the market price paid to all producers, on all the

units they offer for sale, must go up in order to meet the increased demand. Alternatively we could curtail the amount demanded by increasing the amount paid for customers to stop consuming. But in either case, infra-marginal suppliers or curtailing consumers in effect receive unnecessary "rents" when supplies in the form of either more production or less consumption or both increase. Consider consumers for example, who because of unexpectedly bountiful wheat harvest can get bread for less than the maximum price they would be willing to pay—they capture "rent". Similarly, lower-cost electricity suppliers in a competitive market earn "rents" as demand increases, necessitating bringing marginal, progressively higher-cost suppliers onto the market to meet that increased demand.

So when, as PJM proposes, increased demand necessitates bringing higher-cost generators into the market and inducing customers to curtail their consumption, the result is to confer economic "rents" on lower-cost, infra-marginal suppliers, in order to induce the requisite recourse to higher-cost supplies (and losses of rents to purchasers). And this is an economically efficient result.

AFFIDAVIT

Alfred E. Kahn, being duly sworn upon this oath, deposes and says:

1. I am a consultant to an intervenor in this proceeding, and I am duly authorized to make this Affidavit of Verification on its behalf.

2. I have prepared the contents of the foregoing Affidavit with respect to a proposal by PJM Interconnection, LLC, for revisions to its Tariff with regard to demand response compensation, and I hereby verify that the statements of fact and other information contained in that Affidavit are true and correct to the best of my knowledge, information and belief.

/s/ ALFRED E. KAHN
ALFRED E. KAHN

Sworn and subscribed before me this 16th day of Sept., 2009.

/s/ DELORIES S. HARING
DELORES S. HARING
(Notary Public)

DELOREIS S. HARING
Notary Public, State of New York
No. 4766345
Qualified in Tompkins County
Commission Expires June 30, 2011

ATTACHMENT D

UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. EL09-68-000

PJM INTERCONNECTION, INC.

[Sept. 14, 2009]

Affidavit of Ron Belbot On Behalf of Demand Response Supporters

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I. Introduction

I am Ron Belbot, an employee of Severstal Sparrows Point. Severstal Sparrows Point is a 3.5 million ton-per-year, integrated steel plant located outside of Baltimore, Maryland. The plant has 2,500 employees and produces hot-rolled, cold-rolled coated, and tin-plate products. It is the largest single consumer of electricity in Maryland. The electrical data for the plant is:

Peak Load:	230 MW
Average load:	175 MW
Purchased power:	100,000 MWH per month
Behind-the-meter generating station:	150 MW Max Emergency Generation

40-60 MW produced from by product gas

Remainder on natural gas and #6 fuel oil

Sparrows Point joined PJM and became a Load Serving Entity (LSE) in 2003 and purchases all of its power from PJM either on the Day-Ahead or Real-Time Spot Markets. In 2006 and 2007, Sparrows Point participated in the PJM Economic Demand Response Program until the so-called "incentive" program was sunsetted in November 2007. While it was participating, the plant was the largest single site participant and a significant part of the total economic demand response in the BGE zone (see attachment 1). With the ending of the compensation levels in the program, Sparrows Point stopped participating in the program.

Sparrows Point's curtailments were produced by increasing generation with purchased fuels at our internal powerhouse and by curtailing various operations in the plant. When the locational marginal price ("LMP") in the BC zone is above the strike price for generating power on either natural gas or fuel oil, the plant will still increase generation and reduce the amount being purchased, but the savings created by the avoided cost of power is not sufficient to warrant curtailing any of the operation in the plant without the addition of the payment.

The way the program works for this type of large industrial is as follows:

When loads are forecast to be high with correspondingly high LMPs, the operation of each of the facilities is reviewed by production scheduling personnel to see which, if any, of the production units in the plant are in a position to be curtailed, and what the economic off-set has to be to make that curtailment practical. Information like where a unit is in a particular production run, and if that run can be interrupted without affecting quality or damaging equipment, is reviewed. Also, we look at what the effect would be on customer service. If a product is being produced for shipment at a later date, it is much easier to delay and reschedule than if the product is being produced for immediate delivery or is already late. Once the units to be curtailed are identified, the economic impact of the curtailment is established. Factors such as inefficiencies and quality impacts of stopping and starting an operation, the ability to perform needed maintenance during the curtailment, and the fixed costs associated with each of the facilities are all considered in the economic analysis. Once this is established, the actual real-time price is monitored and when it is high enough to be economically worthwhile, the curtailment notification is sent to PJM and the appropriate units are shut down.

While it was participating in the Economic Demand Response Program, Sparrows Point was being self-scheduled. The economic impact of curtailing an operation that had recent unplanned delays that would create significant customer service problems if curtailed made it too much of a risk to schedule curtailments day ahead through PJM dispatch. The above explanation described

the decision process in the near-term. Obviously, longer-term considerations like the current state of the markets, finished inventories on hand, and general relationships between revenues and costs were all factored into the decision.

As you can see, the ability to actually curtail an operation for economic demand response is relatively complicated and very dynamic. Unlike the supply side, there are many factors that determine whether a curtailment is practical on any given day and what the economics have to be to make it worthwhile.

Considering the above explanation of how a large industrial participates in Economic Demand Response, and based on my experience with Sparrow Point's past participation, there are several aspects of the filing proposed by PJM that are inadequate to create a viable robust Economic Demand Response Program.

The first is opportunity. If the compensation amount is the economic driver of the program, then offering full LMP compensation for only certain customers and for only 9% of the time is nowhere near sufficient to create growth. Using that little of an opportunity means every time there is a situation like a shortage of finished inventory, or a production delay on the previous turn that would keep a manufacturer from looking at participation, the opportunity very quickly disappears. Add to that the fact that with only 9% of the hours being above the LMP threshold, there will be many hours that are stand-alone (i.e., non-sequential) hours. These are opportunities that

often will not even be known until after they have passed. Put these together and offering incentives 9% of the time would be de minimus enough to cause an industrial customer not to dedicate the resources to participate in the program.

An arbitrary minimal number like 9% of the hours is also not in the best interest of the market. As a part of the Demand Response Working Group process, PJM staff did an analysis to determine if there was a threshold above which the payment of full LMP for demand response would result in a lower total cost for energy. Their presentation of this analysis (see attachment 2) showed that once the supply curve reached a particular slope, the payment to reduce the load was less than the cost of increasing the LMP for all megawatts by scheduling on the next most expensive generator. As you can see from the presentation, the values in 2006 indicated a percentage of time that was significantly above 9%.

As an end-user that is always short and is paying for electricity through these markets, Severstal Sparrows Point would welcome the increased opportunity to pay a willing demand responder to curtail when that transaction will reduce our overall price. Instead of an arbitrary minimal number like 9%, the market should encourage demand response whenever it will bring more efficiency and lower prices to the market.

It also does not make sense to treat LMP-based customers differently than fixed-rate customers. The value

of the megawatt to the market is LMP; the retail contract of the curtailer is irrelevant to the valuation.

As a closing point, we should stop calling this compensation an "incentive." The value of electricity at any location and any time is LMP. We do not call it an incentive when we pay a nuclear generator $300/MWh when it cost him $30/MWh to produce. LMP is the recognized value of a megawatt and it is the value that should be paid, whether the megawatt is made available to the market by a generator or a demand responder.

AFFIDAVIT
OF
VERIFICAITON

Ron Belbot, being duly sworn upon his oath, deposes and says:

1. I am an employee of Severstal Sparrows Point, a company represented by PJMICC in this proceeding, and I am duly authorized to make this Affidavit of Verification on its behalf.

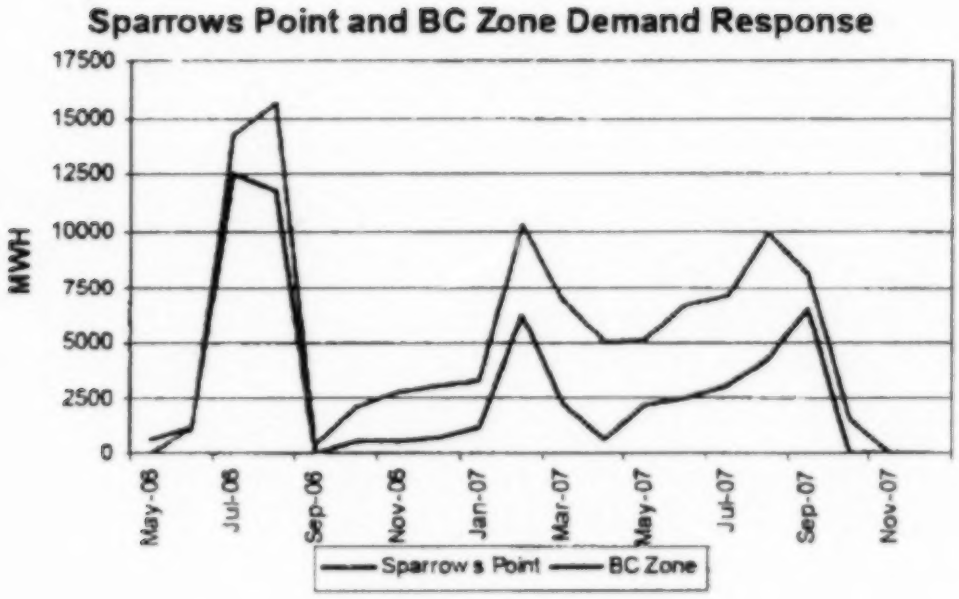
2. I have prepared the contents of the foregoing Affidavit with respect to a proposal by PJM Interconnection, LLC, for revisions to its Tariff with regard to demand response compensation, and I hereby verify that the statements of fact and other information contained in that Affidavit are true and correct to the best of my knowledge, information, and belief.

/s/ RON BELBOT
RON BELBOT

Sworn and subscribed before me this 14th day of Sept. 2009.

/s/ JEAN H. FRASER
JEAN H. FRASER
(Notary Public)

My commission expires 9/17/12


Sparrows Point and BC Zone Demand Response
17500
15000
12500
10000
7500
5000
2500
0
MWH
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07
Jul-07
Sep-07
Nov-07
Sparrows Point
BC Zone

Compensation Threshold Analysis
LMP Impact vs Cost

Serhan Ogur
Pete Langbein
10/11/08

Analysis parameters

- Cost
  1. G&T * DSR mwh reduction
- LMP Impact
  2. Change in LMP * net load purchased in market
     - Use average (9/1/06-8/31/07) percentage of load purchased in the market
       - — Real Time Market – 9/5% when RT PJM LMP > $110
         1. Straight average for 8760 hours = 9.7%
       - — Day Ahead Market – 43.6% when DA PJM LMP > $80
         2. Straight average for 8760 hours = 43.1%
  3. Market purchases are netted on a PJM billing account basis which is consistent with billing process for deviations.
     - Hourly purchases are not determined by location.
- Leverage MMU SOM report average aggregate real time summer 06 supply curve.
  4. Use for represent both real time and day ahead curves
- Determine Cost & LMP Impact at each LMP price point ($1 increments)

Compensation thresholds—key assumptions

- Day Ahead and Real Time LMP impacts are separate

5. Real time Imp does not impact day ahead IMP and vice versa

- Market buyers determined through PJM net interchange:

6. Retail load exposed to RT prices where wholesale supply is based on generation is not captured (netted during interchange process)

    - For example retail rate is real time Imp but supplier self supplies with generation, then it is assumed change in RT LMP has not impact to this market participant

7. Billing account basis (consistent with current PJM practice)—one entity with multiple billing accounts do NOT net out

    - If an entity has 2 billings accounts, 1 for load and 1 for generations the load will appear as a market buyer

- Real time aggregate average supply curve utilized

8. Does not account for real time operations & performance

9. Supply curve extrapolated to day ahead market

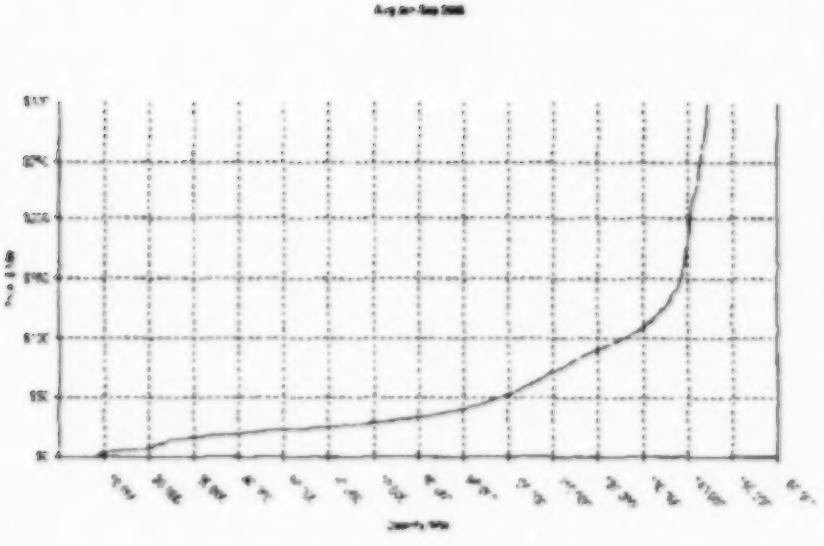
    - Assumes financial participants AND rebid period do not significantly impact shape of supply curve

- Average G&T = $76.86

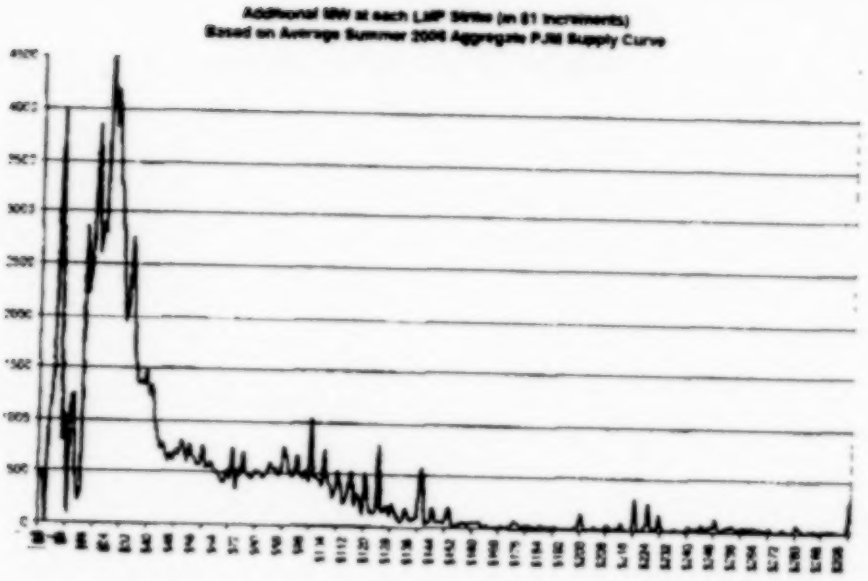
10. Based on current average registered values

Conservative approach to underlying assumptions

2006 Aggregate Average Supply Curve



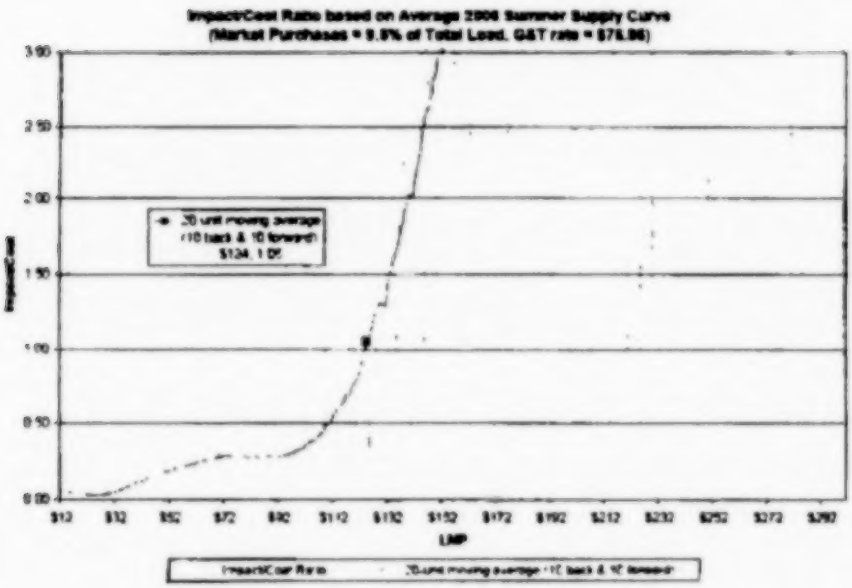
Real Time Result – incremental MWs bid by LMPs



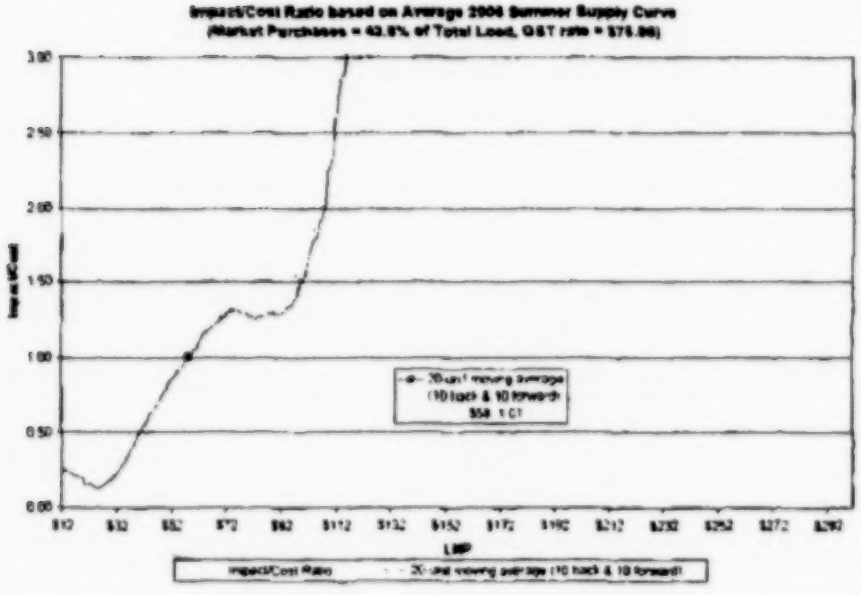
A	B	C	D	E = D - D(-1)	F = A - A(-1)	G = F / E	H = B * D * G	I = C	J = F / G	K = avg [(J(-9) to J(0)]
LMP ($/MW)	Market Buyer %	G&T Rate ($/Mth)	Aggregate Supply (MW)	Incremental Supply (MW)	Incremental Supply ($/MW)	Incremental Supply Unit Cost ($/MW)	LMP Impact ($)	DSR Cost ($)	LMP Impact/DSR Cost Ratio	20 unit moving avg
$124	95%	$76.86	134,704							
$124	95%	$76.86	134,771	67	1	0.0149	$79	$77	1.0	1.1
$125	95%	$76.86	135,059	288	1	0.0035	$38	$77	0.5	1.1

Calculate Impact/Cost Ratio for each LMP price point and then smooth using straight moving average

Real Time Market – LMP Impact/Cost at different LMPs



Day Ahead Market – LMP Impact/Cost at different LMPs



- Threshold results
  11. $58 DA market
  12. $124 RT market

- PJM LoadResponse G&T calculation
- Market Buyer as percentage of total load analysis

G&T Rate Analysis
Based on LoadResponse registrations effective 9/30/07

Bin	Frequency
<20	23
20-40	53
40-60	244
60-80	466
80-100	180
100-120	70
>120	181
	1177

PRICING_ZONE	Average G&T ($ mwh)
AECO	$105.92
AEP	$20.42
AFS	$32.30
BGE	$114.59
COMED	$80.56
DOM	$13.09
DPL	$94.46
DUQ	$62.03
JCPL	$75.79
METED	$94.64
PECO	$85.71
PENELEC	$51.15
PEPCO	$84.85
PPL	$43.89
PSEG	$74.19
RECO	$81.22
Overall average	$70.86

Market Net purchases as % of total load
9/1/06 – 8/31/07

	Day Ahead Pct			Real Time Pct	
	All Hours	hours where PJM DA LMP > $80		All Hours	hours where PJM RT LMP > $110
Mean	43.1%	43.8%		9.7%	9.5%
Min	35.9%	38.0%		5.5%	6.1%
Max	77.6%	60.0%		19.9%	13.7%
Std Dev	3.9%	2.9%		1.6%	1.4%